ENBRIDGE INC. | ANNUAL REPORT 2007

3 SOLID

INVESTMENT PROPOSITIONS

ENBRIDGE®

®ENBRIDGE, the ENBRIDGE LOGO and the ENBRIDGE ENERGY SPIRAL are trademarks or registered trademarks of Enbridge Inc. in Canada and other countries.

THIS IS ENBRIDGE

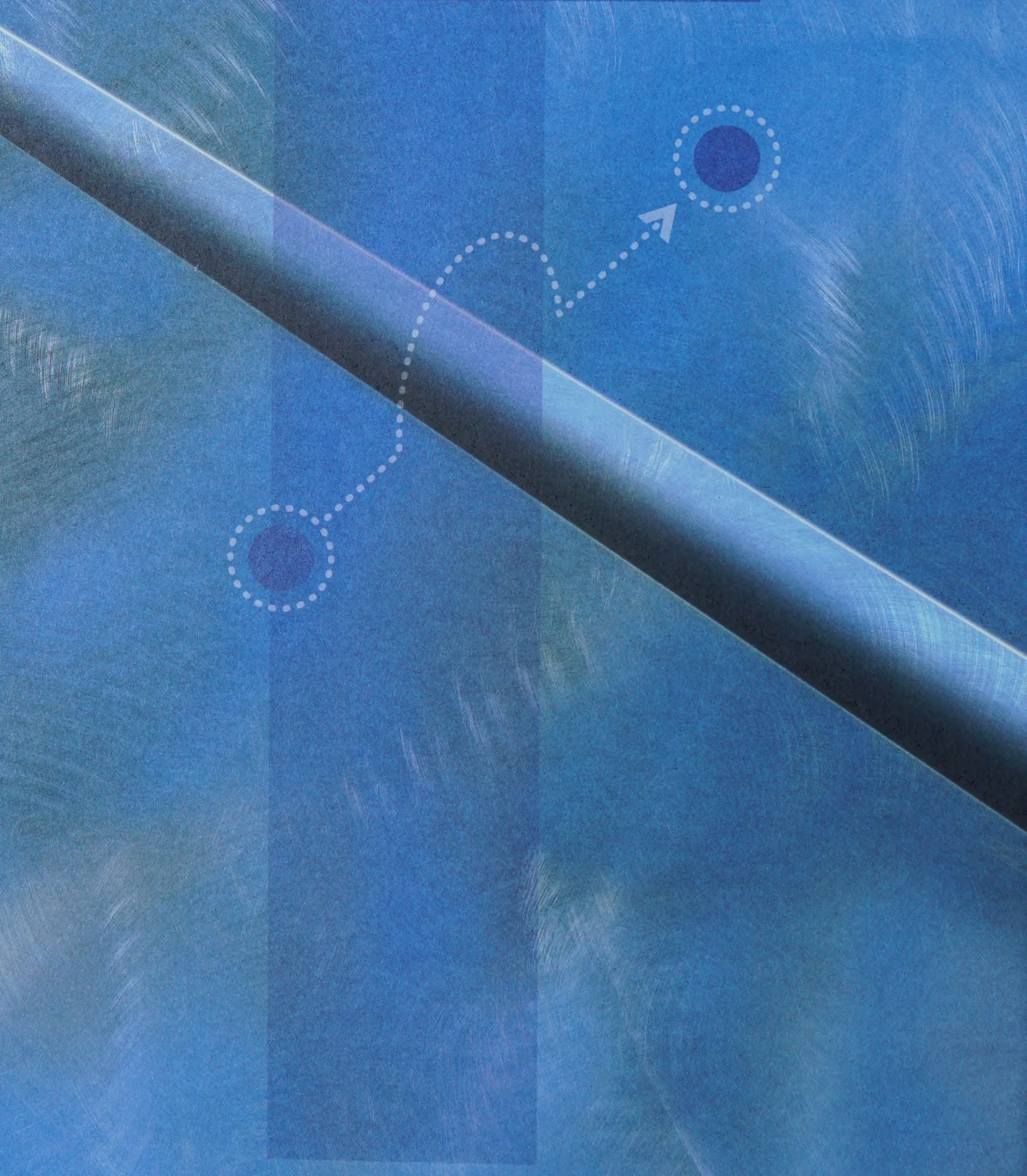
Enbridge Inc. is a leader in energy transportation and distribution in North America and internationally. As a transporter of energy Enbridge operates in Canada and the U.S., the world's longest crude oil and liquids transportation system that delivers approximately 2.2 million barrels per day of crude oil to customers in Canada and the U.S. Midwest. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. The Company has a growing involvement in the natural gas transmission and midstream businesses as well as international operations. Enbridge employs more than 5,500 people primarily in Canada, the U.S. and South America. Enbridge's common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the U.S. under the symbol ENB.

Enbridge's solid investment proposition

We have never been more confident about our ability to create and grow shareholder value. Our investment proposition is very compelling. Through our low-risk business model that allows us both to provide steady income and achieve consistent visible growth, we are delivering solid shareholder returns and will continue to do so for many years.

SOLID INVESTMENT PROPOSITION

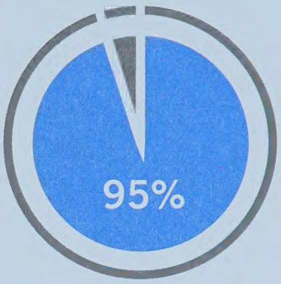
ATTRACTIVE RETURNS AND VERY LOW RISK



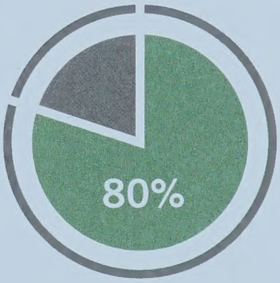
We believe that an investment in Enbridge is safe because of our low-risk business model, which results in highly predictable earnings and strong credit ratings. This enables us to acquire capital at a very low cost that we invest in additional low-risk business opportunities with attractive returns.

We generate 95% of our earnings from our regulated businesses which protects our earnings from fluctuating commodity prices and foreign exchange and interest rates. Moreover, we derive 80% of our earnings from locked-in, long-term shipping contracts, which greatly lowers the risk on all the projects we build.

EARNINGS



95% of our earnings are protected from commodity prices, interest rates and foreign exchange rates.



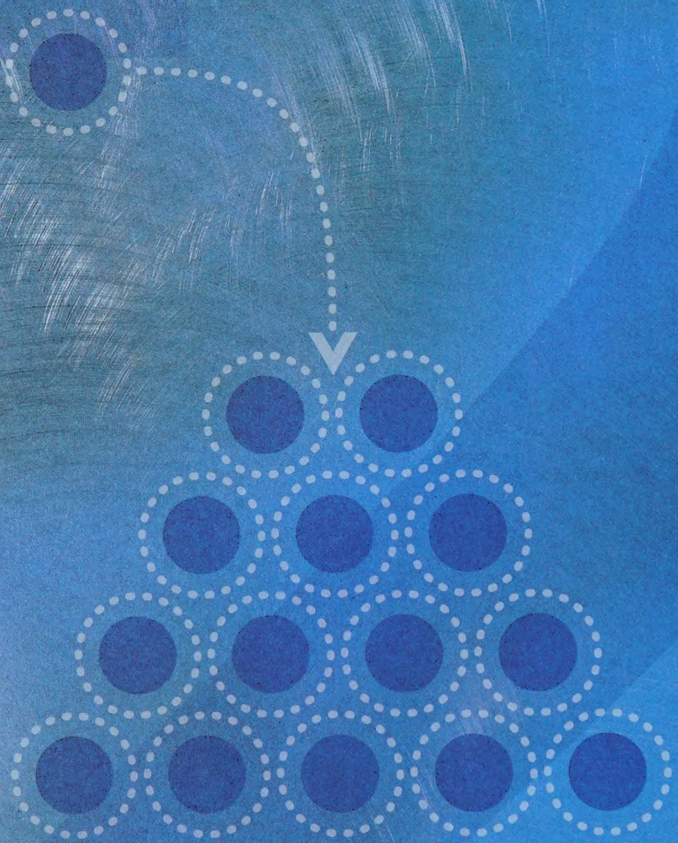
80% of our earnings are from locked-in, volume-insensitive, long-term shipping contracts.

REVENUE

90% of our revenue is generated from a diversified base of investment-grade customers or equivalent.

SOLID INVESTMENT PROPOSITION

CONSISTENT, SUSTAINABLE AND STEADY INCOME



Our track record for total shareholder return is among the best of any company in North America. Over the past decade, Enbridge shareholders have enjoyed an average annual total return of 13%, which is on par with our 54-year annual average return of over 13%.

In the past half century, our dividend has grown on average by close to 10% annually. In early 2008, we increased our dividend for the 13th consecutive year. Currently we aim to pay out 60% to 70% of adjusted operating earnings as dividends.

We intend to continue as we started 54 years ago—consistently delivering solid income growth for shareholders.

3.1%

DIVIDEND YIELD

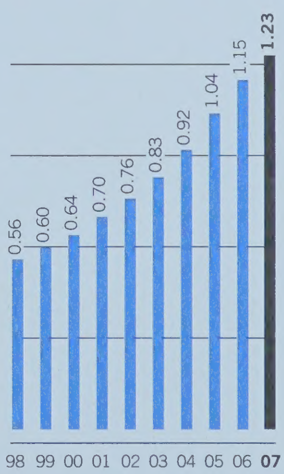
Enbridge delivered a solid 3.1% dividend yield to shareholders in 2007.

13.1%

SHAREHOLDER RETURN

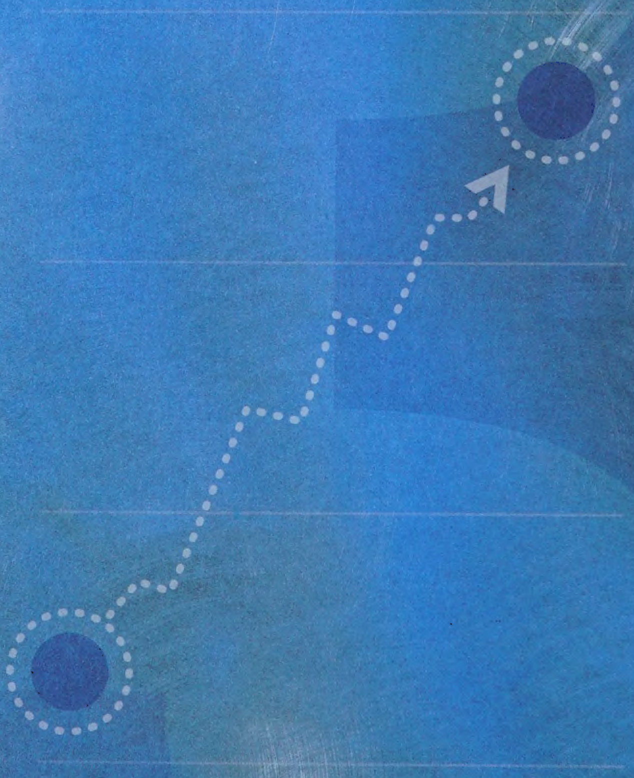
Enbridge has delivered annual total shareholder return averaging 13.1% over the last 54 years.

DIVIDENDS PER COMMON SHARE
(dollars per share)



SOLID INVESTMENT PROPOSITION

HIGHLY PREDICTABLE
LONG-TERM GROWTH



We expect earnings to grow at an annual compounded rate of 10% over the next four years, which is the highest in our industry. Between 2008 and 2011, we intend to bring into service $12 billion of new Liquids Pipelines projects, all of which are commercially secured. These projects have terms which support or enhance the Company's low-risk business profile.

We have an additional $15 billion of potential projects in development that we believe will start to come into service in 2011. Our visible expansion program will result in solid growth in earnings, cash flow and dividends. Over the next four years, we expect our Liquids Pipelines expansions alone will generate average annual growth of 10% in adjusted operating earnings per common share.

9%

PAST EARNINGS GROWTH

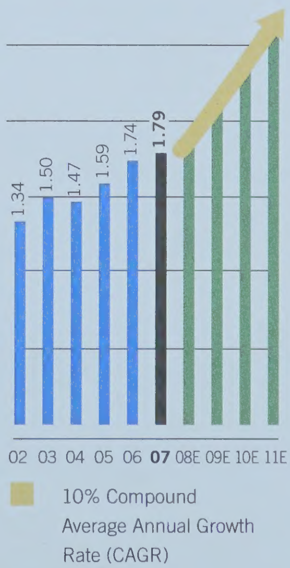
Enbridge's earnings per common share growth has averaged 9% annually over the last 10 years.

10%

ANTICIPATED FUTURE GROWTH RATE

Enbridge's Liquids Pipelines expansions are expected to result in a compound average annual growth rate in earnings per share of approximately 10% over the next four years.

ADJUSTED OPERATING EARNINGS PER COMMON SHARE
(dollars per share)



2007 HIGHLIGHTS

2007 EARNINGS APPLICABLE TO COMMON SHAREHOLDERS

$1.97

per common share

2007 GROWTH IN REPORTED EARNINGS

14%

FINANCIAL
(unaudited; millions of dollars, except per share amounts)

Year ended December 31,	**2007**	2006	2005
Earnings Applicable to Common Shareholders	**700.2**	615.4	556.0
Earnings per Common Share	**1.97**	1.81	1.65
Dividends per Common Share	**1.23**	1.15	1.04
Common Share Dividends	**452.3**	403.1	361.1
Return on Average Shareholders' Equity	**13.6%**	13.9%	13.2%
Debt to Debt Plus Shareholders' Equity	**66.5%**	68.6%	68.9%
OPERATING			
Liquids Pipelines – Deliveries *(thousands of barrels per day)*			
Enbridge System[1]	**2,005**	2,013	1,872
Athabasca System[2]	**164**	190	142
Spearhead Pipeline	**103**	82	–
Olympic Pipeline	**284**	289	–
Gas Pipelines – Average Daily Throughput Volume *(millions of cubic feet per day)*			
Alliance Pipeline US	**1,598**	1,592	1,597
Vector Pipeline	**1,034**	1,015	1,033
Enbridge Offshore Pipelines	**2,060**	2,153	2,102
Gas Distribution and Services[3]			
Volumes *(billions of cubic feet)*	**418**	408	438
Number of active customers *(thousands)*	**1,902**	1,852	1,805
Degree-day deficiency[4]			
Actual	**3,659**	3,355	3,750
Forecast based on normal weather	**3,617**	3,745	3,747

1 *Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border and Line 9 in Eastern Canada.*

2 *Volumes are for the Athabasca mainline only and do not include laterals on the Athabasca System.*

3 *Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

4 *Degree-day deficiency is a measure of coldness which is indicative of volumetric requirements of natural gas utilized for heating purposes. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.*

LETTER TO SHAREHOLDERS

Dear Fellow Shareholders,

We had another financially strong year in 2007. Earnings were $700.2 million or $1.97 per common share, up 14% compared with $615.4 million or $1.81 per common share in 2006. Adjusted earnings per share increased approximately 3% to $1.79, which was consistent with our guidance range and reflects solid operating performance in all our core businesses despite the impact of a weaker U.S. dollar.

Enbridge's Board of Directors increased the annual dividend by 7% in February 2008, the thirteenth annual increase since 1996. Total shareholder return was approximately 3% last year, and has averaged 13% over the past 10 years and more than 13% over the past 54 years. Few companies in North America have such a consistently strong track record.

David A. Arledge
Chair of the Board of Directors

Patrick D. Daniel
President & Chief Executive Officer

Enbridge today is growing at an unprecedented pace and we can predict where, when and how much growth is coming our way.

Enbridge exceeded its strategic objectives in 2007. We brought in more new business than in any prior year in the Company's history, securing commercial agreement on over $5 billion in growth projects. Added to the $7 billion of projects already in our portfolio and a potential $15 billion second wave of growth, we now have a huge pipeline of opportunities that has the potential to deliver outstanding shareholder value for many years to come.

We are now fully engaged in building $12 billion in Liquids Pipelines projects that will come into service starting this year and through to 2011 and will add significantly to cash flows and earnings. All of these projects are commercially secured and many feature capital cost protection, which means returns are attractive and highly predictable. This is the largest capital program in the Company's history.

In 2007, we added close to 500 new employees to support our growth plans. Our thanks go to all of our employees for contributing to the Company's success in 2007 and for setting the stage for the growth to come.

Our current energy delivery infrastructure is very well positioned to serve growing sources of supply and new market demand.

Today, Enbridge moves 62% of Canada's oil exports to the U.S., representing 11% of the U.S.'s daily crude oil imports and making us the largest single conduit of crude oil into the U.S. We believe Canada and Enbridge stand to play an even larger role in the future in providing U.S. markets with a secure, reliable and growing source of crude oil supply. The primary source of supply growth in Canada is northern Alberta's oil sands, which is now the largest resource play in the world.

Our liquids pipelines are 'hard-wired' between the oil sands and the U.S. refining markets. Our strategy is to broaden access to those refining markets for growing oil sands production, which is forecast to triple by 2016.

Over the next four years, we plan to complete $12 billion of new major projects, including:

- The Waupisoo Pipeline (capital expenditure: $0.6 billion) from the oil sands to Edmonton.
- The Southern Access Expansion in the U.S. and Canada (US $2.1 billion and $0.3 billion, respectively).
- The Southern Access Extension (US $0.5 billion) will expand access to the crude oil hub at Patoka, Illinois.
- The Alberta Clipper project in Canada and the U.S. ($2 billion and US $1 billion, respectively) will provide additional capacity to our mainline system.
- We are also now building our Southern Lights Pipeline (US $2.2 billion), which will provide capacity to transport diluent from Chicago to Alberta's oil sands producers.
- In late 2007, we announced the Fort Hills Project ($2 billion) to develop pipeline and terminaling facilities for the Fort Hills, Alberta, oil sands project (subject to final approvals).

In addition, we are competing for another $15 billion of opportunities that would come into service from 2011 onward. These include mainline expansions, new market access through mainline extensions, regional pipelines and contract terminaling.

One of these projects is the Texas Access Pipeline, a proposal to transport crude oil from Alberta to the Texas Gulf Coast. Enbridge and Exxon Mobil Corporation began soliciting binding shipper commitments for Texas Access in late 2007.

Enbridge's gas pipeline and distribution assets also made solid contributions to cash flow and earnings per share in 2007. Both are positioned strategically for growth.

Our major interests in the Alliance and Vector pipelines, which today move natural gas from Western Canada to Chicago and southern Ontario, are both fully contracted to 2015. Vector, which completed one expansion in 2007, is now planning another to be in service by 2009. We are also growing our natural gas gathering, processing and transmission infrastructure in the Gulf of Mexico, where Enbridge transports approximately 40% of all current deepwater natural gas production.

Through our interest in Enbridge Energy Partners, we are very active in the development of gas gathering and processing infrastructure in the Barnett Shale, Bossier and Anadarko gas plays.

Enbridge Gas Distribution (EGD) is Canada's largest natural gas distribution utility with 1.8 million customers and the second fastest growing gas distribution company in North America. We are adding about 45,000 customers every year on the strength of our franchise in metropolitan Toronto. Incentive regulation will be introduced this year, positioning EGD to generate even more value.

Our investments in Colombia and Spain again performed well in 2007 and we are pleased with the contributions they are making.

Enbridge has long advocated for renewable and alternative energy and energy efficiency. Our new wind farm in Ontario is under construction and is scheduled to begin producing electricity during the latter half of this year. This is our fourth wind farm and, when completed, will be the second largest in Canada.

Enbridge takes the issue of climate change very seriously. In February this year, we announced Enbridge will lead a group of 20 energy industry participants to explore development of a large-scale commercial carbon dioxide sequestration operation.

The health and safety of our employees, contractors and the public is a critical measure of our performance. Everyone at Enbridge was deeply saddened that two tragic accidents in 2007 claimed the lives of a customer in Toronto, Ontario, and two Enbridge employees, Dave Mussati Jr. and Steve Arnovich, based in Superior, Wisconsin. The people of Enbridge will never rest in our efforts to live up to our commitment of protecting the health and safety of all individuals affected by our activities.

We are very pleased to welcome Catherine L. Williams to the Board of Directors, effective November 2007. Ms. Williams has extensive experience in the energy sector. The Board wishes to greatly thank Donald Taylor, who retired from the Board in May 2007, for his many years of dedicated service.

In January 2008, we announced changes in our senior management team and we are confident this new structure, coupled with the dedication and drive of all our employees, will help us successfully deliver on our strategy.

The number and scale of the low-risk, high-return opportunities we have before us is unprecedented. We are focused on excellence in the execution of our expansion projects. We have never been more confident in our ability to create value for our customers and for you, our shareholders.

On behalf of the Board,

David A. Arledge
Chair of the Board of Directors

Patrick D. Daniel
President and Chief Executive Officer

March 10, 2008

ENBRIDGE'S LEADERSHIP TEAM

With $12 billion in expansion projects approved and underway and a potential $15 billion second wave of growth projects, Enbridge is focusing on both current operations and the construction of these projects.

We have structured our executive management team to ensure the successful execution of the Company's exciting growth plans and to maintain the success of its current operations. Our goal is to continue to deliver superior returns to our shareholders and maintain the credibility the Company has earned with all of its stakeholders.

Left to right: *Stephen J.J. Letwin, J. Richard Bird, Stephen J. Wuori, Patrick D. Daniel, Bonnie D. DuPont, Al Monaco, David T. Robottom.*

EXECUTIVE MANAGEMENT TEAM

Patrick D. Daniel, President & Chief Executive Officer
Mr. Daniel is responsible for all of the Company's operating and staff segments. He is also a member of the Enbridge Inc. Board of Directors. Prior to his current appointment, he was President & COO, and also previously served as CEO of Interprovincial Pipe Line. He also held senior management positions with Hudson's Bay Oil & Gas and Home Oil. Mr. Daniel has been with the Enbridge group of companies since 1986.

J. Richard Bird, Executive Vice President, Chief Financial Officer & Corporate Development
Mr. Bird is responsible for all financial affairs of the Company and corporate planning, mergers, acquisitions and corporate development. Immediately prior to being appointed to this position in January 2008, Mr. Bird served as Executive Vice President, Liquids Pipelines, including responsibility for initiatives to secure $12 billion of crude oil pipeline development opportunities. He joined Enbridge in 1995 as Vice President and Treasurer.

Bonnie D. DuPont, Group Vice President, Corporate Resources
Ms. DuPont is responsible for Human Resources, the Corporate Secretariat function, Public & Government Affairs, and Information Technology. She also is responsible for Enbridge's Corporate Social Responsibility strategies and has led that initiative through processes that resulted in Enbridge being named one of the World's 100 Most Sustainable Companies for the past three successive years. Ms. DuPont joined Enbridge in 1998.

Stephen J.J. Letwin, Executive Vice President, Gas Transportation & International
Mr. Letwin is responsible for all aspects of Enbridge's natural gas operations, including oversight of Enbridge Gas Distribution and Enbridge Gas New Brunswick. He is also responsible for International operations, the Alliance, Vector and offshore natural gas pipelines, and has overall responsibility for Enbridge Energy Partners. Mr. Letwin joined Enbridge in 1999 as President & Chief Operating Officer, Energy Services.

Al Monaco, Executive Vice President, Major Projects
Mr. Monaco is Executive Vice President, Major Projects and leads the Major Projects group, which is responsible for project execution once commercial viability for a major project has been established. Immediately prior to assuming this role in January 2008, Mr. Monaco was President, Enbridge Gas Distribution and responsible for Enbridge's eastern Canadian regulated and unregulated operations. He joined Enbridge in 1997.

David T. Robottom, Group Vice President, Corporate Law
Mr. Robottom is responsible for the Company's legal functions. He has over 28 years of legal and in-depth management experience, having been the Chief Executive Officer of Fraser Milner Casgrain LLP. Immediately prior to joining Enbridge in 2006, he was a senior partner with Stikeman Elliott LLP.

Stephen J. Wuori, Executive Vice President, Liquids Pipelines
Mr. Wuori is Executive Vice President, Liquids Pipelines and is responsible for all crude oil and liquids pipeline operations in North America, including Enbridge Pipelines and its related liquids pipelines operations, and Enbridge's many opportunities for new pipelines to transport growing oil sands production. Immediately prior to being appointed to this position in January 2008, he served as Executive Vice President, Chief Financial Officer & Corporate Development. Mr. Wuori joined the Enbridge group of companies in 1980.

GEOGRAPHICALLY WELL POSITIONED

Enbridge is ideally positioned for growth. The fact that our existing infrastructure is located in strategic geographical locations (north and south, east and west) has put us in an unparalleled position to expand and extend our energy delivery networks to reach new markets for our customers throughout North America and the world.

173 BILLION

Our liquids pipelines are 'hard wired' between Canada's oil sands—the largest resource play in the world—and the U.S. refining market. With an estimated 173 billion barrels of oil sands reserves, Canada ranks second only to Saudi Arabia in global oil reserves.

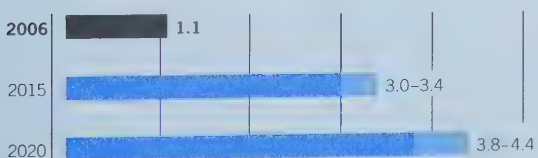
45,000 CUSTOMERS

Enbridge Gas Distribution is adding about 45,000 customers a year on the strength of our position in Toronto, Canada's most populous city.

40%

Enbridge's offshore natural gas pipelines transport about 40% of all current deepwater natural gas production in the Gulf of Mexico.

OIL SANDS PRODUCTION IS GROWING
(million barrels per day)



Source: Canadian Association of Petroleum Producers

OPERATIONS AND ASSETS

LIQUIDS PIPELINES

Enbridge is changing the face of how crude oil is distributed in North America.

We currently have $12 billion in Liquids Pipelines expansion projects under construction or awaiting regulatory approval and expected to be in service between now and 2011.

Over the next four years—expanding and extending from our existing geographically well-positioned infrastructure—we will almost double the size of our Liquids Pipelines business, further diversifying the markets we serve and playing an even more significant role in energy delivery in North America.

We have an additional $15 billion of projects in development that we anticipate will be in service from 2011 onward and have the potential to further extend our customers' reach to new markets in North America and other parts of the world.

'HARD WIRED' TO CANADA'S OIL SANDS

Enbridge is 'hard wired' to the oil sands. We are the preeminent pipeline provider for oil sands producers. Our Athabasca pipeline system is now connected to six different oil sands projects. We are poised for considerable growth. Our Waupisoo Pipeline, which is scheduled to be in service by mid-2008, will link oil sands producers to their upgraders and refineries in Edmonton; and in late 2007, we announced plans to construct and operate pipeline and terminaling facilities for the Fort Hills, Alberta, oil sands project.

Oil sands production is growing at an unprecedented rate. It is expected to grow from today's 1 million barrels per day to more than 3.4 million barrels per day by 2016. Oil sands producers require more pipeline capacity to reach new markets.

Enbridge's $12 billion expansion program is driven by these oil sands fundamentals and designed to help producers broaden access to markets for oil sands crude.

2.2

MILLION BARRELS A DAY

Enbridge is Canada's major transporter of crude oil. We move about 2.2 million barrels per day of crude oil through the world's longest, most sophisticated crude oil pipeline system.

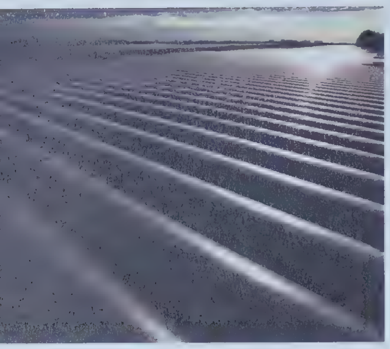
62%

OF CANADIAN EXPORTS

Enbridge exports 70% of Western Canadian oil, representing 62% of all Canadian oil exports to the U.S.

No.1

Enbridge provides about 11% of daily imports to the United States—the largest single conduit of oil into the U.S. in any single day.



Pipe stockpiled near Edmonton awaits deployment to Enbridge's Waupisoo Pipeline, which is scheduled to be in service by the middle of 2008.

'HARD WIRED' TO U.S. REFINERIES

Crude oil refiners in the United States are looking to source more crude oil from Canada's oil sands.

Enbridge already has an extensive pipeline network in the U.S. This provides us the economies of scale to add capacity and extend our network. An important part of our $12 billion expansion program is providing secure capacity to link petroleum transportation hubs and refineries in the Midwest.

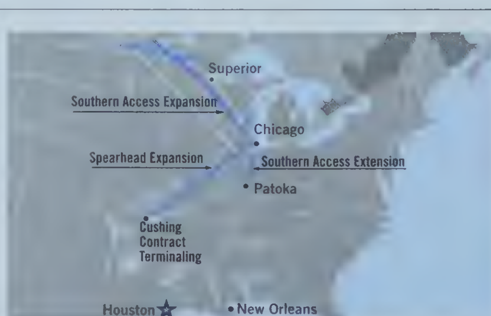
GROWTH WAVE 1

$12 billion of commercially secured projects underway (2007 to 2011)

PROJECT	IN-SERVICE DATE	STATUS
Athabasca Laterals	2007	Completed
Waupisoo	2008	Under Construction
Southern Access Expansion*–Edmonton, AB to Pontiac, IL	Stage 1–2006-2008 Stage 2–2009	Under Construction
Southern Access Extension–Chicago to Patoka, IL	2009	Awaiting Regulatory Approval
Spearhead Expansion–Chicago, IL to Cushing, OK	2009	Awaiting Regulatory Approval
Line 4 Extension–Edmonton to Hardisty, AB	2009	Awaiting Regulatory Approval
Contract Terminaling—Hardisty, Stonefell, AB	2008–2009	Various Stages
Alberta Clipper*–Edmonton, AB to Superior, WI	2010	Approved by NEB; U.S. approvals pending
Southern Lights–Chicago, IL to Edmonton, AB	2010	Under Construction
Fort Hills–Oil Sands to Edmonton, AB	2011	In Progress

* *Southern Access Expansion US and US portion of Alberta Clipper will be undertaken by Enbridge Energy Partners.*

Wave 1 Growth Opportunities, Canada



Wave 1 Growth Opportunities, U.S.

GROWTH WAVE 2—EXPANSION BEYOND 2011

Enbridge's positioning should serve the Company equally well as it competes for the more than $15 billion wave of opportunities that we now have in development to be in service in 2011 and beyond. These opportunities include mainline expansions, regional pipelines, new market access through mainline extensions, longer term new market access opportunities and contract terminaling.

Other initiatives include: the Gateway Pipeline Project to export oil sands crude oil to Asia-Pacific markets and California; and an extension of our mainline system to the east coast of the U.S. into the Philadelphia area.

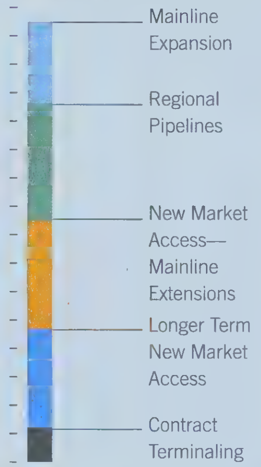
Customers in Canada and the United States are calling for a significant amount of additional crude oil terminal capacity at both ends of Enbridge's North American crude oil mainline system. Expansion of storage in key locations contributes to North American spare capacity and energy security. While this demand is primarily for term contract storage, customers are also seeking operational tankage at key locations on the mainline.

US GULF COAST OPPORTUNITIES

Enbridge's latest initiative, a proposed joint venture with ExxonMobil Pipeline Company, is the Texas Access Pipeline to move crude oil originally sourced from Canada's oil sands to refiners on the Texas Gulf Coast. An open season to solicit binding commitments from shippers began in December 2007.

GROWTH WAVE 2 PROJECTS

$15.5 BILLION



$2 BILLION

On the strength of our operating and pipeline development experience in Alberta's oil sands region, Enbridge was chosen in late 2007 to develop $2 billion in pipeline and terminaling facilities for the Fort Hills oil sands project, subject to final approvals.

Wave 2 Gateway Petroleum Export and Condensate Import Pipelines

Wave 2 Texas Access Pipeline and Eastern PADD II

1.8

MILLION

Enbridge Gas Distribution has 1.8 million customers and has growing customer bases in Quebec and New Brunswick.

The fundamentals of the natural gas business in Ontario are strong because natural gas

is the most efficient fuel for burner tip applications; has a significant price advantage over fuel oil and electricity; is clean burning and environmentally attractive relative to other energy sources; and is now critical to the Ontario power supply mix.

Enbridge Gas Distribution is adding approximately 45,000 customers a year on the strength of its position in the Greater Toronto Area.

GAS DISTRIBUTION AND SERVICES

Enbridge Gas Distribution, our natural gas distribution franchise in Ontario, is Canada's largest gas distribution utility and one of the fastest growing gas distribution utilities in North America.

We are adding approximately 45,000 customers a year on the strength of our position in the Greater Toronto Area, which has a growing population that is now over 5.5 million people.

In addition to organic growth, Enbridge Gas Distribution is focused on achieving incremental value through incentive regulation and growing its unregulated businesses.

Enbridge also owns 32.1% of Noverco Inc., which holds a majority interest in Gaz Métro Limited Partnership, the company that distributes natural gas in Quebec.

GAS DISTRIBUTION GROWTH OPPORTUNITIES

We plan to optimize the performance of Enbridge Gas Distribution through incentive regulation (IR), which will begin in 2008. IR reduces regulatory costs. It also provides shareholder incentives for improved efficiency and revenue growth, more flexibility for utility management and more stable rates.

Enbridge Gas Distribution expects to have over two million customers by 2010.

Ontario requires 7,100 megawatts of gas-fired power generation capacity in the next few years. By 2015, natural gas is expected to account for 33% of Ontario's total energy production, compared with 15% today.

Enbridge is targeting growth over the next five years in its unregulated businesses, which include: natural gas storage; small scale generation such as distributed energy; renewable energy; and retail energy services.

GAS PIPELINES

Enbridge's natural gas pipelines are superbly positioned to take advantage of growth in the key strategic gas producing and consuming regions of North America.

Through Enbridge Offshore Pipelines, we are growing our natural gas gathering, processing and transmission infrastructure in the Gulf of Mexico, where today we transport approximately 40% of all current deepwater natural gas production. This further positions us to transport natural gas into the U.S. northeast and southeast.

The Company has major stakes in the Alliance and Vector systems which transport natural gas from Western Canada to the U.S. Midwest and southern Ontario. Vector expanded capacity in 2007 to 1.2 billion cubic feet per day from 1 billion cubic feet per day and is now planning for the next expansion expected to be completed by 2009. Both of these expansions are underpinned by long-term contracts. Alliance is well positioned for opportunities arising from the development of natural gas in northeast British Columbia, Alaska and Canada's arctic region.

Enbridge Energy Partners is a large and growing natural gas gatherer and processor in the Anadarko Basin, Barnett Shale and Bossier Sands of Texas, which are three of the top four areas for natural gas development in the United States.

NATURAL GAS PIPELINES GROWTH OPPORTUNITIES

Gulf of Mexico offshore is a prolific natural gas region where Enbridge has two new pipelines—Atlantis, which started up in December 2007, and Neptune which is expected to start up this year. A third—the Thunder Horse lateral pipeline to our Okeanos System—is expected to be in service in late 2008.

Prospects for growth in processing and gathering pipelines to serve Texas onshore natural gas production are strong.

Longer term, Alliance and Vector are well positioned to connect Arctic natural gas development to U.S. and eastern Canadian markets.

15%

TEXAS NATURAL GAS

Enbridge Energy Partners transports approximately 15% of Texas natural gas production.

Enbridge Offshore Pipelines has a premier position in the Gulf of Mexico, with interests in 11 transmission and gathering pipelines in five major pipeline corridors in Louisiana and Mississippi offshore waters.

3000

KILOMETRES

The Alliance System transports natural gas from the Western Canada Sedimentary Basin to the U.S., extending 3,000 kilometres (1,875 miles) from Fort St. John, British Columbia, to Chicago, Illinois.

Connecting with the Alliance System at Chicago, the 560-kilometre (348-mile) Vector Pipeline provides natural gas supplies for local distribution and end-user customers in Illinois, Indiana, Michigan and Ontario.

100%

PIPELINE NETWORK

CLH's operating assets include 100% of the refined products pipeline network in Spain, as well as 63% of the total product storage capacity in the country.

OCENSA is well positioned for two major upstream heavy oil developments. By the end of this year, OCENSA expects to be moving 150,000 barrels a day from the Castilla Field. The Rubiales Field, which has about 621 million barrels of estimated reserves and current production of around 18,000 barrels a day, offers further growth prospects for OCENSA.

INTERNATIONAL

Enbridge has energy-delivery investments in South America and Europe:

- 24.7% interest in Oleoducto Central S.A. (OCENSA) crude oil pipeline in Colombia; and
- 25% of Compañia Logistica de Hidrocarburos CLH, S.A. (CLH), Spain's largest refined products transportation and storage business.

We invested in OCENSA in 1994 and CLH in 2002. Both are delivering consistently solid returns and have strong growth prospects for the future.

In early 2008, Enbridge announced it has begun the process of evaluating strategic alternatives for monetizing its investment in CLH. Alternatives include the potential sale of some or all of Enbridge's shareholding in the company. Proceeds from any monetization of the CLH investment would be applied toward funding Enbridge's extensive list of expansion projects in its core North American crude oil pipeline business.

RENEWABLE AND GREEN ENERGY DEVELOPMENT

Enbridge has a role to play in the responsible use of energy.

We are investing today to encourage the use of renewable and alternative energy including wind power and new energy technology such as fuel cells.

We are also positioning ourselves for the future by participating in the emerging technology of carbon dioxide (CO_2) capture, pipelining and sequestration, and participating in research for the safe transport of ethanol through pipelines.

The OCENSA pipeline is Colombia's largest pipeline system, stretching from oilfields in the central interior of the country to the Caribbean coast.

CO_2 Capture, Pipelining and Sequestration

Enbridge plans to be a leading participant in CO_2 capture, pipelining and sequestration developments, which are widely considered to be one of the most immediate and meaningful ways to reduce overall CO_2 emissions and address the challenges posed by climate change.

In early 2008, Enbridge announced it will lead a group of 20 energy industry participants in the Alberta Saline Aquifer Project (ASAP), a broad-based, industry-supported initiative to investigate the feasibility of the long-term commercial sequestration of CO_2 in deep saline aquifers.

ASAP builds on our carbon reinjection experience in Texas gas processing facilities. It is the first project of its kind in Canada and will play a major role in advancing industry and government's knowledge of CO_2 sequestration.

FUEL CELL POWER PLANT

Enbridge's leading-edge Direct FuelCell®-Energy Recovery Generation (DFC®-ERG) Power Plant is a global first—producing ultra-clean electricity from energy that is recovered from natural gas pipeline systems.

In 2007, Enbridge completed construction of Phase 1 of its fuel cell pilot plant and began constructing Phase 2. The compact power plant will eventually produce 2.2 megawatts of electricity, enough to provide power to 1,500 residences.

Once the pilot plant is built, we plan to replicate it throughout our pipeline network in Ontario, and the DFC®-ERG will be marketed to other natural gas pipeline companies throughout North America.

For more details on Enbridge's fuel cell power plant innovation, please see our 2007 Corporate Social Responsibility Report at www.enbridge.com/csr2007.

Enbridge Income Fund owns interests in two wind farms in Alberta and one in Saskatchewan.

100%

WORKING INTEREST

Enbridge owns a 100% working interest in the $500-million Ontario Wind Power project that we are now constructing in Bruce County, Ontario. When completed later this year it will be the second largest wind farm in Canada.

90,000 HOMES

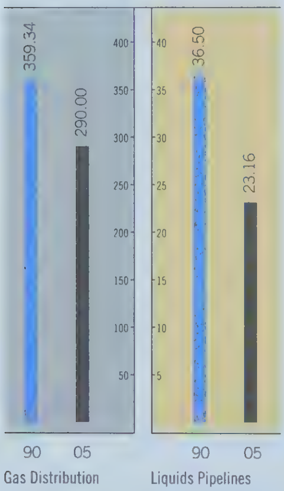
Enbridge's four wind power projects have a combined capacity of more than 250 megawatts, enough electricity to meet the power requirements for about 90,000 homes, or about 35% of the power consumed by our Canadian crude oil mainline.

CORPORATE SOCIAL RESPONSIBILITY

-18%

In 2005, Enbridge achieved its corporate target to reduce its Canadian direct GHG emissions by 15% below 1990 levels. We are now 18% below our targets. Our new interim target is to reduce our Canadian direct GHG emissions to 20% below 1990 levels by 2010.

ENBRIDGE'S CANADIAN DIRECT GHG EMISSIONS, 1990 VS 2005



Enbridge's drive for operating excellence is built on a strong foundation of corporate values and corporate social responsibility (CSR) policies and practices.

Our corporate values are integrity, accountability, innovation, flexibility, value creation, and social responsibility. By living these values as part of our daily activities, our goal is to fulfill our CSR commitments.

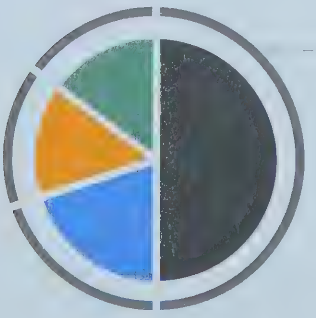
We define CSR as: conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights; and engaging, respecting and supporting the communities and cultures in which we live and work.

Our CSR commitments ensure that we put a priority on public and employee safety, a clean and healthy environment, and strong, vibrant communities.

We have adopted a CSR Policy that covers business ethics and transparency, environment, health and safety, stakeholder relations, employee relations, human rights, and community partnerships and investments. This policy applies to activities undertaken by, or on behalf of, Enbridge and our subsidiaries anywhere in the world where we manage operations.

Our CSR performance will be detailed in Enbridge's 2008 Corporate Social Responsibility Report, which will provide details about our environmental, economic and social performance against targets.

Enbridge continues to practice sustainable community investment by strengthening the four "building blocks" that create vibrant communities: Health & Community, Education, Environment, and Arts & Culture. As part of its commitment to CSR, Enbridge also is investing in renewable energy resources, including wind power, solar panels, and fuel cells. Visit www.enbridge.com to read our CSR report.



Community Investment Focus in 2007

Enbridge's voluntary contributions in Canada and the United States support charitable and non-profit organizations that contribute to the economic and social development of communities where we live and work.

- **50%** Health & Community
- **20%** Education
- **15%** Environment
- **15%** Arts & Culture

CORPORATE GOVERNANCE

At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance in respect of the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews the results. The Board also oversees identification of the Company's principal risks on an annual basis, monitors risk management programs, reviews succession planning, and seeks assurance that internal control systems and management information systems are in place and operating effectively.

Additional information about Enbridge's Corporate Governance, Board of Directors and Senior Management team can be found in the Corporate Governance section of Enbridge's website, at http://www.enbridge.com/investor/corporategovernance/.

Photo Left to Right:

George K. Petty
San Luis Obispo, California
Corporate Director

Catherine L. Williams
Calgary, Alberta
Corporate Director

E. Susan Evans
Calgary, Alberta
Corporate Director

David A. Leslie
Toronto, Ontario
Corporate Director

Dan C. Tutcher
Houston, Texas
Corporate Director

Patrick D. Daniel
Calgary, Alberta
President & Chief Executive Officer, Enbridge Inc.

David A. Arledge
Naples, Florida
Chair of the Board, Enbridge Inc.

Robert W. Martin
Toronto, Ontario
Corporate Director

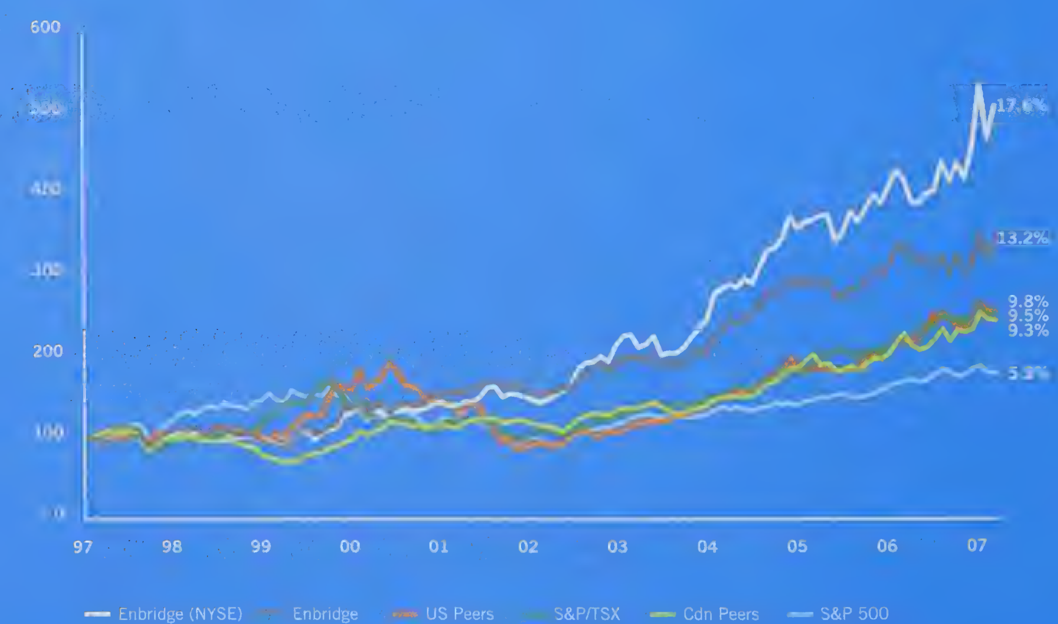
J. Lorne Braithwaite
Malahide, County Dublin, Ireland
Corporate Director

James J. Blanchard
Beverly Hills, Michigan
Senior Partner, DLA Piper U.S., LLP

J. Herb England
Naples, Florida
President & CEO, Stahlman-England Irrigation Inc.

Charles E. Shultz
Calgary, Alberta
Chair & Chief Executive Officer, Dauntless Energy Inc.

10-YEAR TOTAL SHAREHOLDER RETURN



Canadian Peers: Canadian Utilities, Emera, TransCanada, TransAlta.
US Peers: Aquila, CMS Energy, Dominion, DTE Energy, Dynegy, El Paso, Equitable Resources, National Fuel Gas, NiSource, Sempra, Spectra, Questar and Williams.

MANAGEMENT'S DISCUSSION AND ANALYSIS

CONSOLIDATED RESULTS

FINANCIAL PERFORMANCE[1]

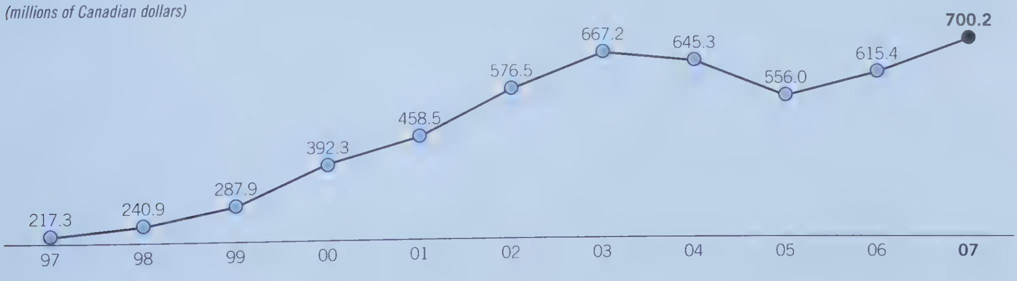
(millions of dollars, except per share amounts)	**2007**	2006	2005
Liquids Pipelines	**287.2**	274.2	229.1
Gas Pipelines	**69.7**	61.2	59.8
Sponsored Investments	**96.9**	86.8	64.8
Gas Distribution and Services	**184.1**	178.2	178.8
International	**95.1**	83.2	87.4
Corporate	**(32.8)**	(68.2)	(63.9)
Earnings Applicable to Common Shareholders	**700.2**	615.4	556.0
Earnings per Common Share	**1.97**	1.81	1.65
Diluted Earnings per Common Share	**1.95**	1.79	1.63

1 *Financial Performance data have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).*

Earnings applicable to common shareholders were $700.2 million for the year ended December 31, 2007, or $1.97 per share, compared with $615.4 million, or $1.81 per share, in 2006. The $84.8 million increase was primarily due to colder than normal weather and strong performance at Enbridge Gas Distribution (EGD), lower corporate interest expense and increased earnings at Enbridge Energy Partners, L.P. (EEP). The 2007 results also included a significant benefit from favorable legislated Canadian tax changes enacted in 2007. The positive factors were partially offset by lower contributions from the Aux Sable natural gas fractionation facility and Energy Services.

Earnings applicable to common shareholders were $615.4 million for the year ended December 31, 2006, or $1.81 per share, compared with $556.0 million, or $1.65 per share, in 2005. The $59.4 million increase in earnings was primarily the result of higher earnings from the Enbridge crude oil mainline system, strong results from EEP and from Aux Sable. The 2006 results also included $48.9 million from the revaluation of future income tax balances due to tax rate reductions enacted in 2006. These positive factors were partially offset by a lower earnings contribution from EGD as the weather in the Ontario market was significantly warmer than normal during 2006.

Earnings Applicable to Common Shareholders
(millions of Canadian dollars)



FORWARD LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Management's Discussion and Analysis (MD&A) to provide Enbridge Inc. (Enbridge or the Company) shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; anticipated in-service dates and weather.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

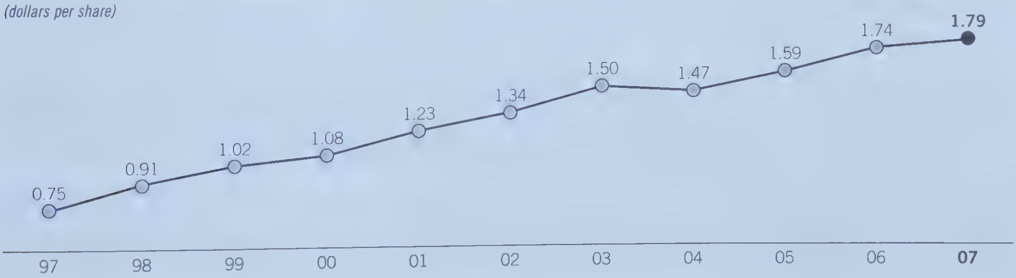
This MD&A contains references to adjusted operating earnings, which represent earnings applicable to common shareholders adjusted for non-operating factors. Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value. Management uses adjusted operating earnings to set targets and assess performance of the Company. Also, the Company's dividend payout target is based on adjusted operating earnings. Adjusted operating earnings is not a measure that has a standardized meaning prescribed by GAAP and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

ADJUSTED OPERATING EARNINGS

(millions of dollars, except per share amounts)	**2007**	2006	2005
GAAP earnings as reported	**700.2**	615.4	556.0
Significant after-tax non-operating factors and variances:			
Liquids Pipelines			
Impact of tax changes	**(1.2)**	–	–
Gas Pipelines			
Offshore property insurance recovery from 2005 hurricanes	**(5.3)**	–	–
Sponsored Investments			
Dilution gains on EEP Class A unit issuance	**(11.8)**	–	(8.9)
EEP unrealized derivative fair value losses/(gains)	**6.3**	(6.5)	5.0
EEP gain on sale of assets of Kansas Pipeline Company	**(3.0)**	–	–
Impact of tax changes	**(1.9)**	(6.0)	–
Gas Distribution and Services			
Warmer/(colder) than normal weather affecting EGD	**(14.2)**	36.9	–
Energy Services unrealized derivative fair value losses	**2.4**	–	–
Aux Sable unrealized derivative fair value losses	**28.1**	–	–
Dilution gain in Noverco (Gaz Metro unit issuance)	**–**	(4.0)	(7.3)
Impact of tax changes	**(27.7)**	(28.9)	–
International			
Gain on land sale in CLH	**(5.2)**	–	(7.6)
Corporate			
Impact of tax changes	**(30.2)**	(14.0)	–
Adjusted Operating Earnings	**636.5**	592.9	537.2
Adjusted Operating Earnings per Common Share	**1.79**	1.74	1.59

Each of the significant non-operating factors and variances is described in the Results of Operations sections for the respective business segment.

Adjusted Operating Earnings per Common Share
(dollars per share)



Significant operating factors that increased earnings in 2007 included:

- Customer growth and higher operating margins at EGD;
- Strong operating results and an increased ownership interest in EEP; and
- Lower corporate costs due primarily to lower interest expense.

Significant operating factors that decreased earnings in 2007 included:

- Lower earnings from Aux Sable due to realized derivative losses; and
- The impact of a weaker U.S. dollar on all U.S.-based pipelines.

2007 Commercial and Construction Accomplishments:

- An Open Season commenced on the Texas Access crude oil pipeline to the Gulf Coast.
- Enbridge entered into an agreement to develop pipeline and terminal facilities for Phase 1 and subsequent phases of the Fort Hills oil sands project at a preliminary cost estimate for the initial facilities of $2 billion.
- The Neptune offshore pipelines were completed.
- The Ontario Wind Project was approved by provincial regulators and construction commenced.
- Regulatory applications were filed for the Canadian portion of the Alberta Clipper project and Line 4 Extension.
- Construction activities progressed on Southern Access Expansion, Southern Lights Pipeline, Waupisoo Pipeline and Hardisty Terminal.
- Shipper commitments and FERC approval were obtained for the Spearhead Pipeline Expansion.

CORPORATE STRATEGY

CORPORATE VISION AND KEY OBJECTIVE

Enbridge is an energy delivery company that transports natural gas and crude oil, which are used for many purposes, including to heat homes, power transportation systems and provide fuel and feedstock for industries. The Company's vision is to be North America's leading energy delivery company and its key objective is to generate superior shareholder value. The Company will deliver superior shareholder value through an investment proposition consisting of:

- above industry-average earnings per share growth;
- a strong, secure risk-reward investment profile and financial position; and
- a balanced combination of near term dividend income and superior dividend growth and capital appreciation.

STRATEGY

Enbridge's 2007 Strategic Plan consists of three broad strategies to generate superior shareholder value and position the Company for the energy environment of the future.

1. **Expand Existing Core Businesses**

   Development and operation of oil and gas energy delivery assets is our primary strength and a core competency. Enbridge's existing systems are well positioned to take advantage of evolving hydrocarbon supply and demand fundamentals and, given the challenging environment for acquisitions, most of our core business growth in the near term is expected to come from organic project development largely driven by the oil sands transportation opportunity. Strategies for each core business are included in the sections to follow.

2. **Focus on Operational Excellence, People and the Environment**
   Enbridge will continue its focus on operational excellence, including cost efficiency, safety and reliability, effective project management, customer relationships and effective stakeholder relations. Enbridge will also focus on effective strategies for recruitment, development and retention of employees in addition to reinforcing its strong reputation for environmental stewardship and community investment.

3. **Develop New Platforms for Growth and Diversification**
   Enbridge believes it is also important to develop new growth platforms that complement the existing core asset base to sustain longer term growth and diversify the business. Initiatives include CO_2 sequestration and transportation, liquefied natural gas (LNG) regasification, natural gas storage and new energy technologies.

To successfully pursue these strategies, the Company must mitigate certain business risks. These risks, and the Company's strategies for managing them, are described under Risk Management.

Enbridge's strategy is reviewed annually with direction from the Board of Directors. In light of its unprecedented Liquids Pipelines growth program, in 2007 the Company modified its strategy to simplify and somewhat narrow the Company's focus. The 2007 strategy de-emphasized International as a growth driver due to an extremely competitive environment that makes it difficult to find assets or new projects with acceptable risk/return profiles. Expansion is instead focused on the North American market.

The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

COMPETITIVE ADVANTAGE

The Company's ability to execute its strategy and realize its corporate vision depends primarily on three key strengths. These include the strategic position of the Company's major assets, the diversification of its businesses and its consistent focus on customer service.

The Company's assets are well positioned in North America. In the liquids business, the Company operates a major conduit between U.S. markets and the geopolitically attractive oil sands reserves in Western Canada. Enbridge has economies of scale and scheduling flexibility because of its multiple separate lines and the flexibility to move over 95 different grades of crude oil. Enbridge's existing right of way is valuable in developing major expansion projects due to increasing environmental and land-owner challenges in securing energy corridors. Also, the Company serves a diversity of markets because of the extent and reach of its pipeline systems. The gas businesses are also well located. The Ontario gas utility franchise in Toronto benefits from perennially high customer addition rates due to immigration and urbanization.

The Company's sources of earnings and growth are diversified among liquids pipelines, gas pipelines, gas distribution and international investments. As well, the Company is actively exploring new growth platforms that would further diversify and complement existing core businesses.

The Company is focused on adding value for customers and improving customers' profitability. This focus has aligned the Company with supply-demand fundamentals, which have consistently formed a basis for the Company's strategy. The Company seeks to provide value to customers in a variety of

innovative ways including provision of access to new markets for producers and new sources of supply for refiners; diversifying the supply of diluent required for transportation of heavy crude; and protection of batch quality and value.

GROWTH PROJECTS

The thrust of the Company's current strategy is growth through development and construction of new infrastructure. The Company is advancing the development of a number of organic growth projects, some of which are summarized below, which support annual organic earnings per share growth rates averaging 10% over the next four years. These projects are at various stages of development. While different milestones are relevant to each, for simplicity management has classified projects into two categories – Commercially Secured and Under Development. Commercially Secured projects, including those being undertaken by EEP, are all expected to be completed within the next four years through 2011. Projects Under Development are those which the Company believes it has a reasonable probability of competitively winning and could exceed the value of the projects already commercially secured. This "second wave" would contribute to continued acceleration of earnings growth post-2011. While Enbridge will continue to pursue acquisitions that are accretive to earnings on an opportunistic basis, growth project execution remains the Company's primary focus.

(in billions of Canadian dollars) Commercially Secured Projects[1]	Estimated Capital Cost[2]	Expenditures to Date	Expected In-Service Date	Status
Liquids Pipelines				
1. Waupisoo Pipeline	$0.6 billion	$0.4 billion	Mid-2008	Construction approximately 67% complete
2. Fort Hills Pipeline System	$2.0 billion	No significant expenditures to date	Mid-2011	Customer contract secured
3. Southern Access Mainline Expansion – Canadian portion	$0.3 billion	$0.1 billion	2006 - 2009 (in stages)	Under construction
4. Alberta Clipper – Canadian portion	$2.0 billion[3]	No significant expenditures to date	Mid-2010	Awaiting regulatory approval
5. Line 4 Extension	$0.3 billion	No significant expenditures to date	Q1 2009	Awaiting regulatory approval
6. Southern Lights Pipeline	$2.2 billion	$0.4 billion	Late 2010	Under construction (U.S.)
7. Southern Access Extension	$0.5 billion	No significant expenditures to date	Early 2009	Awaiting regulatory approval
8. Spearhead Pipeline Expansion	$0.1 billion	No significant expenditures to date	2009	Awaiting regulatory approval
9. Hardisty Terminal	$0.4 billion	$0.1 billion	2008 - 2009	Under construction
10. Stonefell Terminal	$0.1 billion	$0.1 billion	2009	Under construction
Sponsored Investments (EEP)				
11. Project Clarity – East Texas	$0.6 billion	$0.6 billion	2007 - 2008 (in stages)	Substantially complete
12. North Dakota System Expansion	$0.2 billion	No significant expenditures to date	Early 2010	Awaiting regulatory approval
13. Southern Access Mainline Expansion – U.S. portion	$2.1 billion	$1.1 billion	2008 - 2009 (in stages)	Under construction
14. Alberta Clipper – U.S. portion	$1.0 billion[3]	No significant expenditures to date	Mid-2010	Awaiting regulatory approval
Total	**$12.4 billion**			
Gas Distribution and Services				
15. Ontario Wind Project	$0.5 billion	$0.3 billion	Late 2008	Under construction

Projects Under Development[1]	Potential In-Service Date	Status
Liquids Pipelines		
16. Various Mainline Expansions	2012 - 2015	In planning stage
17. Texas Access Pipeline	2011	Obtaining shipper commitments
18. Eastern PADD II/Eastern Canada Initiatives	2010 - 2015	In commercial discussions
19. Gateway Condensate Import	2012 - 2014	In commercial discussions
20. Gateway Petroleum Export	2012 - 2014	In commercial discussions
21. Various Oil Sands Regional Facilities	2011 - 2015	In planning stage
Sponsored Investments (EEP)		
22. Various Liquids Pipelines Mainline Expansions	2010 - 2015	In planning stage
Gas Distribution and Services		
23. Rabaska LNG Facility	2011 - 2012	In commercial discussions

1 *Descriptions of each project are included in the strategy section for each business segment.*
2 *These amounts are estimates only and subject to upward or downward adjustment based on various factors.*
3 *2007 dollars, excluding allowance for funds used during construction (AFUDC).*

Risks related to the development and completion of organic growth projects are described under Risk Management.

COMMERCIALLY SECURED PROJECTS

△ **Liquids Pipelines**

1 Waupisoo Pipeline
2 Fort Hills Pipeline System
3 Southern Access Mainline Expansion—Canadian portion
4 Alberta Clipper—Canadian portion
5 Line 4 Extension
6 Southern Lights Pipeline
7 Southern Access Extension
8 Spearhead Pipeline Expansion
9 Hardisty Terminal
10 Stonefell Terminal

○ **Sponsored Investments (EEP)**

11 Project Clarity—East Texas
12 North Dakota System Expansion
13 Southern Access Mainline Expansion—U.S. portion
14 Alberta Clipper—U.S. portion

□ **Gas Distribution and Services**

15 Ontario Wind Project

PROJECTS UNDER DEVELOPMENT

▲ **Liquids Pipelines**

17 Texas Access Pipeline
18 Eastern PADD II/Eastern Canada Initiatives
19 Gateway Condensate Import
20 Gateway Petroleum Export

■ **Gas Distribution and Services**

23 Rabaska LNG Facility

DIVIDENDS

The Company has paid common share dividends since its inception. Based on estimated 2008 dividends, the rate of increase has averaged 10% since 1953. The Company's dividend payout ratio reflects a strong and stable long-term outlook for the business. While balancing shareholders' preference for income and its own need for capital, the Company targets to pay out approximately 60% to 70% of adjusted operating earnings as dividends. In 2007, dividends paid per share were 69% of adjusted operating earnings per share (2006 – 66%, 2005 – 65%).

The chart below shows dividends per share for the last 10 years and estimated dividends for 2008, based on the quarterly dividend of $0.33 per common share declared by the Board of Directors on February 5, 2008. Average annual growth is 9%.

Effective with dividends payable on March 1, 2008, participants in the Company's Dividend Reinvestment and Share Purchase Plan will receive a 2% discount on the purchase of common shares with reinvested dividends.

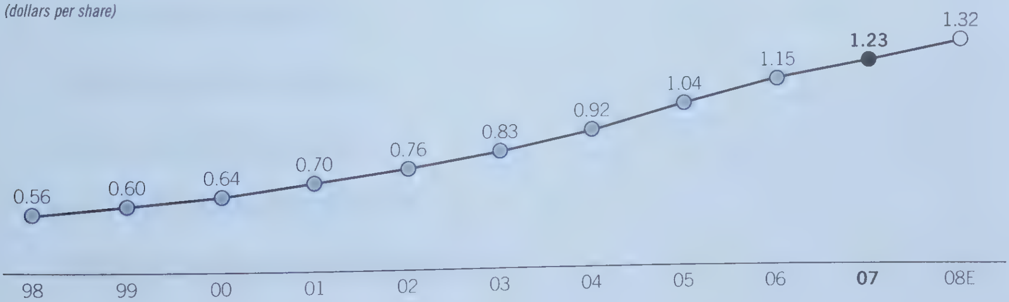
CORPORATE SOCIAL RESPONSIBILITY

At Enbridge, being socially responsible means doing things right, and doing the right thing. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights; and engaging, respecting and supporting the communities and cultures with which the Company works.

A comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees. Examples include compliance with applicable Sarbanes-Oxley requirements and the Canadian securities regulators' corporate governance guidelines and rules, the use of internal and external reviews and audits to assess each business segment's compliance with government regulations and our internal policies and management systems, and to provide guidance for making improvements. Employee and Director compliance with Enbridge's Statement on Business Conduct, a majority of independent Directors on the Company's Board of Directors as well as plain and open communication with stakeholders are other examples of stewardship and accountability.

Environmental initiatives include pursuing alternative and renewable energy technologies, minimizing pipeline leaks by conducting on-going inspection and maintenance programs and the development of a strategy to reduce greenhouse gas emissions. This strategy involves improving the energy efficiency of pipelines, encouraging the efficient use of natural gas by customers and replacing older cast iron pipe at EGD with new polyethylene mains. Enbridge engages employees on health and safety issues through training, communication programs and the establishment of local and regional environmental, health and safety committees.

Dividends per Common Share
(dollars per share)



Stakeholder relations involves developing and maintaining positive relationships with employees, contractors, suppliers, customers, landowners, investors, environmental groups, business partners, government agencies and regulators, provincial, state and federal legislators, local officials, community residents and the media. Initiatives include early-stage project consultation with a variety of stakeholders on organic growth projects and public awareness programs on pipeline safety.

Enbridge supports universal human rights and reinforces this principle with comprehensive policies and practices addressing human rights. For example, Enbridge was one of the first Canadian companies to adopt the Voluntary Principles on Security and Human Rights, which stress the importance of promoting and protecting human rights throughout the world and the constructive role business can play in advancing these goals.

The Company makes voluntary contributions to charitable and non-profit organizations in the areas of: education, health, environment, social services, arts and culture, community leadership and volunteerism, in order to contribute to the economic and social development of communities where Enbridge employees live and work.

While Enbridge is focused on generating long-term value for investors, Corporate Social Responsibility defines the Company's commitment to achieving and sustaining that objective in a socially and environmentally responsible way.

CORE BUSINESSES

The Company's activities are carried out through five business units:

- Liquids Pipelines, which includes the operation of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons;
- Gas Pipelines, which consists of the Company's interests in natural gas pipelines including Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines;
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF) and EEP, both managed by Enbridge;
- Gas Distribution and Services, which consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses; and
- International, which includes the Company's two energy-delivery investments outside of North America.

LIQUIDS PIPELINES

Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines in Canada and the United States.

EARNINGS

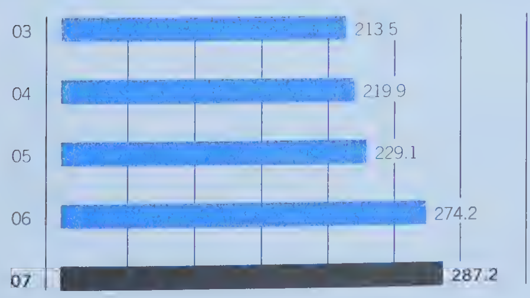
(millions of dollars)	**2007**	2006	2005
Enbridge System	**202.5**	202.3	170.1
Athabasca System	**53.7**	52.8	48.6
Olympic Pipeline	**9.9**	6.5	–
Spearhead Pipeline	**10.0**	6.3	(1.1)
Southern Lights Pipeline	**6.8**	–	–
Feeder Pipelines and Other	**3.1**	6.3	11.5
Impact of tax changes	**1.2**	–	–
	287.2	274.2	229.1

Liquids Pipelines earnings were $287.2 million in 2007 compared with $274.2 million in 2006. The increase was due primarily to strong contributions from Olympic and Spearhead Pipelines as well as the recognition of an allowance for equity funds used during construction (AEDC) on the Southern Lights Pipeline.

Liquids Pipelines earnings were $274.2 million in 2006 compared with $229.1 million in 2005. The increase resulted from strong results from the Enbridge System, the commencement of operations of the Spearhead Pipeline and the acquisition of the Olympic Pipeline.

Revenues in the Liquids Pipelines segment increased to $1,090.9 million in the year ended December 31, 2007 from $1,048.1 million in the year ended December 31, 2006. The increased revenue was partially due to increased volumes on Spearhead Pipeline and higher tolls on Olympic Pipeline. In addition, revenue reflected full year contribution from Spearhead Pipeline and Olympic Pipeline.

Revenues in the Liquids Pipelines segment increased to $1,048.1 million in the year ended December 31, 2006 from $881.0 million in the year ended December 31, 2005. The increased revenue was due to a higher revenue requirement on the Enbridge System as well as the start up of Spearhead Pipeline, which commenced operations in the first quarter of 2006 and Olympic Pipeline, which was acquired in the first quarter of 2006.



Liquids Pipelines Earnings
(millions of dollars)

The increase in Liquids Pipelines earnings in 2007 was due primarily to strong contributions from Olympic and Spearhead Pipelines as well as the recognition of an allowance for equity funds used during construction on the Southern Lights Pipeline.

Liquids Pipelines

ENBRIDGE SYSTEM

The mainline system is comprised of the Enbridge System and the Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through five adjacent pipelines with a combined capacity of approximately 2.0 million barrels per day (bpd), the system transports various grades of crude oil and diluted bitumen from Western Canada to the Midwest region of the United States and Eastern Canada. Also included in the Enbridge System and located in Eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd. The average utilization in 2007 was 80% and it is expected to increase in 2008.

Results of Operations

Enbridge System earnings were $202.5 million for the year ended December 31, 2007 compared with $202.3 million for the year ended December 31, 2006. The effect of increased incentive tolling settlement (ITS) metrics and higher System Expansion Program (SEP) II utilization were offset by increased operating costs and higher taxes in the Terrace component, resulting in consistent earnings in 2007 and 2006.

Enbridge System earnings were $202.3 million for the year ended December 31, 2006 compared with $170.1 million for the year ended December 31, 2005. This increase reflected a number of factors including lower oil loss costs, favourable ITS performance and, within Terrace, lower taxes, higher toll revenues and the impact of higher volumes generating surcharge revenue.

Incentive Tolling

Tolls on the Enbridge System are governed by various agreements, which are subject to the approval of the National Energy Board (NEB). The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the ITS applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement and the SEP II Risk Sharing Agreement. Tolls on the core mainline system have been governed by incentive tolling settlements since 1995.

The ITS allows the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In addition, performance metrics were added to the current ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets and may incur penalties if performance falls short of specified thresholds.

Enbridge achieved total metrics bonuses of approximately $11 million for the year ended December 31, 2007 compared with approximately $10 million for the years ended December 31, 2006 and 2005.

In conjunction with the Terrace Agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The agreements govern both current and future shippers on the pipeline and establish tolls each year based on an agreed capacity and an allowed revenue requirement. Where actual volumes on the pipeline fall short of the agreed capacity and Enbridge is unable to fully collect its annual revenue requirement, the deficiency is rolled into the subsequent year's tolls for collection from shippers at that time and a receivable, referred to as the Transportation Revenue Variance (TRV) is recognized. This basis may affect the timing of recognition of revenues compared with that otherwise expected under GAAP for companies that are not rate-regulated.

Enbridge pays taxes each year only on the tolls collected in cash; therefore, the tax payable on the TRV lags behind the recognition of the revenue by one year. As the Terrace capacity is increasingly utilized, there will be less TRV recorded and more cash tolls collected. This will result in the Company paying taxes in future years on both the prior year's TRV and the current year's cash tolls.

ATHABASCA SYSTEM

The Athabasca System, a 540-kilometre (340-mile) synthetic and heavy oil pipeline built in 1999, links the Athabasca oil sands in the Fort McMurray, Alberta region, to a pipeline transportation hub at Hardisty, Alberta. The Athabasca System, which has a design capacity of approximately 570,000 bpd, is currently configured to transport 390,000 bpd. It also includes the MacKay River, Christina Lake, Surmont and Long Lake facilities, growing merchant tankage facilities and the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil tankage services.

Results of Operations

Earnings for the year ended December 31, 2007 were $53.7 million compared with $52.8 million for the year ended December 31, 2006. The $0.9 million earnings increase was due to earnings from infrastructure additions, partially offset by higher operating costs including increased property taxes and minor leak remediation costs.

Earnings for the year ended December 31, 2006 were $52.8 million, an increase of $4.2 million from 2005. Infrastructure additions contributed to the increase, partially offset by higher operating expenses.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca System, which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning return on equity, based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns as well as the cost of providing service; therefore, Enbridge is recording a receivable in these years. This treatment ensures that the revenue recognized each period is in accordance with the contract. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

OLYMPIC PIPELINE

In February 2006, Enbridge acquired a 65% interest in the Olympic Pipeline from BP Pipelines. Olympic is the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 300 miles

(480 kilometres) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP is the operator of the pipeline.

Results of Operations

Earnings for the year ended December 31, 2007 were $9.9 million compared with $6.5 million for the year ended December 31, 2006. Higher tolls as well as a full year contribution from Olympic Pipeline resulted in this $3.4 million increase. Tolls are adjusted annually to reflect the estimated cost of service for the year and any over or under collections from prior years.

SPEARHEAD PIPELINE

The Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of this 125,000 bpd pipeline has continued to surpass Enbridge's expectations and with the support of shippers, the Spearhead Pipeline Expansion is underway.

Results of Operations

Earnings increased to $10.0 million for the year ended December 31, 2007 compared with $6.3 million for the year ended December 31, 2006. Spearhead Pipeline commenced operations at the beginning of March 2006; therefore, 2007 earnings reflect a full year of operations as well as increased throughput.

SOUTHERN LIGHTS PIPELINE

This pipeline is currently under construction in the United States and received regulatory approval in Canada in the first quarter of 2008. Upon completion, the 180,000 bpd 20-inch diameter Southern Lights Pipeline will transport diluent from Chicago to Edmonton, Alberta.

Results of Operations

The Company is entitled to collect an AEDC in tolls once the pipeline is in service. Earnings for 2007 reflect the AEDC related to construction funding during 2007.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta, interests in a number of liquids pipelines in the United States, liquid tankage facilities and business development costs related to Liquids Pipelines activities.

Results of Operations

Earnings in Feeder Pipelines and Other were $3.1 million for the year ended December 31, 2007 compared with $6.3 million for fiscal 2006 and $11.5 million for fiscal 2005. The decrease in earnings over the past two years is primarily due to increased business development costs related to the Company's organic growth projects.

STRATEGY

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. In addition to incentive tolling models as discussed, the Liquids Pipelines strategy focuses proactively on understanding Western Canadian supply and downstream demand fundamentals and then proposing timely new or reconfigured infrastructure solutions to improve customer profitability.

Supply and Reserves

The Liquids Pipelines growth strategy is based on the development of the vast resource of the Western Canadian Sedimentary Basin (WCSB). Increasingly, development of the oil sands resource is driving investment opportunity. The NEB estimates that total Western Canada production will be 2.5 million bpd[1] at the end of 2007. At the end of 2006, remaining established conventional oil reserves in Western Canada were estimated to be 3.7 billion barrels[2] and remaining established reserves from oil sands were estimated at 173 billion barrels[3]. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 13.4% of the worldwide estimated proved reserves[4]. In addition, the vast Canadian oil sands resource is geopolitically secure and in close proximity to U.S. markets.

Demand

The Company's liquids pipelines depend on the demand for crude oil and other liquid hydrocarbons produced in Western Canada. Deliveries from the pipeline system are made in the Prairie Provinces, the Province of Ontario and the Great Lakes and Midwest regions of the United States. These deliveries are principally to refineries, either directly or through the connecting pipelines of other companies. Major refining centres are located near Sarnia, Nanticoke, and Toronto, Ontario; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; Chicago, Illinois; the Patoka/Wood River, Illinois area; Detroit, Michigan; and Toledo, Ohio. Through Company initiatives, Canadian crude oil has started to penetrate markets in southern PADD II (the U.S. Midwest) with the Spearhead Pipeline to Cushing, Oklahoma as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.

For the past four years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S.[5] The largest market for WCSB crude oil is located in the U.S. PADD II region. Over the last two years, deliveries of WCSB crude oil into this market have increased by 50,900 bpd corresponding to the growth in WCSB crude oil supply in 2007[6,7]. In the same two year period, there have been increased deliveries into other U.S. markets including PADD V (the U.S. West coast) and PADD III, where deliveries have increased by 35,300 bpd and 55,400 bpd, respectively. Deliveries into PADD IV (the U.S. Rocky Mountains) have declined by 11,800 bpd. Western Canadian demand is served by local supply and has remained relatively flat over the last two years[6]. During 2007, greater volumes of Western Canadian crude oil were transported to Ontario[7], displacing Atlantic Basin crude oil[6].

KEY COMPONENTS OF THE LIQUIDS PIPELINES STRATEGY

The Liquids Pipelines strategy is driven by the industry's need for export capacity alternatives, economic sources of diluent and U.S. refiners' need to maintain diversified sources of supply. The five key components of the Liquids Pipelines strategy are described below as well as progress made to date and future plans towards further advancing the strategy.

1. Develop Regional Oil Sands Infrastructure

Increasing oil sands production will require significant new infrastructure upstream of the mainline and the Company is developing a number of projects to support the development of the Alberta oil sands. Growth opportunities already secured include construction of the Waupisoo Pipeline and the

1 *National Energy Board 2007 Estimated Production of Canadian Crude Oil and Equivalent Table 1*
2 *Canadian Association of Petroleum Producers Statistical Handbook 2007*
3 *Alberta Energy and Utilities Board Alberta's Reserves 2006 and Supply/Demand Outlook/Overview*
4 *Oil and Gas Journal's Worldwide Look at Reserves and Production, December 24, 2007*
5 *"Table 38: Year-To-Date Imports of Crude Oil and Petroleum Products into the United States by Country of Origin, January – October 2007", Energy Information Administration/Petroleum Supply Monthly, December 2007*
6 *"Disposition of Domestic Light and Heavy Crude Oil and Imports – 2007 & 2005", National Energy Board*
7 *"2007 & 2005 Estimated Production of Canadian Crude Oil and Equivalent", National Energy Board*

establishment of agreements with Fort Hills Energy, L.P. to develop pipeline and terminaling facilities for the Fort Hills oil sands project.

Waupisoo Pipeline

The 30-inch diameter, 380-kilometre (236-mile) long crude oil pipeline from the Cheecham terminal on the Athabasca Pipeline to Edmonton received approval from the Alberta Energy and Utilities Board (effective January 1, 2008 the Energy Resources Conservation Board (ERCB)) in February 2007. The initial capacity of the line will be 350,000 bpd and is expandable to a maximum of 600,000 bpd with additional pumping units. Capital costs for the project are currently expected to approximate $0.6 billion. Capital cost risks are shared between the Company and the shippers. Construction is approximately 67% complete and the pipeline is expected to be in service mid-2008.

Athabasca Pipeline Expansion Projects

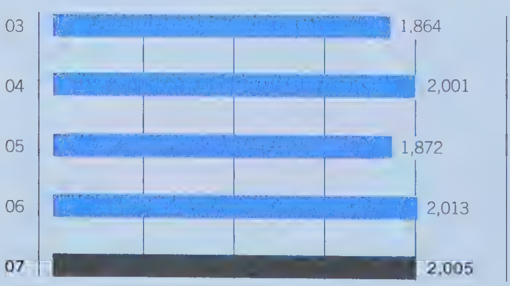
In April 2007, the construction and commissioning of the Athabasca Pipeline expansion projects were completed. These projects include the addition of pumping stations at Elk Point and Cheecham as well as modifications to existing pumping stations. The Elk Point expansion is in-service and the Cheecham expansion is awaiting production from the Long Lake Oil Sands Project.

Surmont Oil Sands Project

The Surmont Oil Sands Project consists of pipeline and tank facilities at the Cheecham Terminal on the Athabasca Pipeline. Enbridge has 25-year agreements with ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. to provide pipeline transportation services on the Athabasca Pipeline with the flexibility for the Surmont Shippers to transfer their production to the proposed Waupisoo Pipeline to the Edmonton area. Enbridge has completed construction of the Surmont facilities and has placed them into service.

Long Lake Oil Sands Project

The Company has 25-year lateral agreements with Nexen Inc. and OPTI Canada Inc. to provide pipeline transportation services for the Long Lake Project. Under the terms of the agreements, Enbridge will construct, own and operate the pipeline and tank facilities required by the Long Lake Project as well as pipeline laterals and tank facilities at the Cheecham terminal on the Athabasca Pipeline. The construction of the laterals and facilities at Long Lake was completed in the first half of 2007 and shipments commenced in February 2008. The Company started collecting stand-by fees in 2007.



Enbridge System Deliveries
(thousands of barrels per day)

Deliveries on the Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border and Line 9 in Eastern Canada.

Fort Hills Pipeline System

The Company announced that it has entered into an agreement with Fort Hills Energy, L.P. to develop pipeline and terminaling facilities to meet the requirements of Phase 1 and subsequent phases of the Fort Hills oil sands project. The preliminary plan for the Fort Hills Pipeline System includes a diluted bitumen pipeline from the mine site north of Fort McMurray to the upgrader site northeast of Edmonton with a capacity of 250,000 bpd, and a parallel 70,000 bpd diluent return pipeline. The system will also consist of terminaling facilities at the mine site and the upgrader, and ancillary pipelines between the upgrader and the Edmonton pipeline hub. The estimated cost of the initial pipeline system and related facilities is approximately $2.0 billion, subject to finalization of scope and estimate refinement, with planned in-service dates in mid-2011. Construction of the Fort Hills Project including the associated pipeline facilities is subject to final approvals by the Fort Hills' partners and various regulatory approvals and permits.

2. Expand Mainline Capacity

The Chicago refining market is expected to remain a major destination for Western Canadian crude. The Company is working with shippers and refiners to further expand this market and markets beyond, both in Canada and the United States, through the Southern Access Mainline Expansion and the Alberta Clipper Project. The Line 4 Extension Project is a third, smaller debottlenecking project that has been undertaken to expand capacity.

Southern Access Mainline Expansion Project

The Southern Access Mainline Expansion Project is currently under construction and will ultimately add a total of 400,000 bpd incremental capacity to the mainline system. The U.S. segment of the expansion from the Canada/U.S. border to Flanagan, Illinois, is being undertaken by EEP and the Canadian segment from Hardisty, Alberta to the Canada/U.S. border is being undertaken by Enbridge. Tolling principles were approved by the Federal Energy Regulatory Commission (FERC) and the NEB in 2006.

Having completed phase one of the Canadian portion of this expansion in 2006, phase two construction activities are currently underway. These involve upgrades at 18 pump stations to improve pumping effectiveness.

In the United States, the expansion will be completed in stages, finishing in 2009. Currently, construction activities are underway on the 321-mile (517-kilometre) section from Superior to Delavan, Wisconsin with over 94% of welding completed. This first stage of construction of the U.S. portion of this expansion is on schedule for completion in the second quarter of 2008 and will add capacity of approximately 190,000 bpd.

Based on construction costs experienced on the initial phase of the project, the expected cost of the project has been updated to an estimated US$2.4 billion (Enbridge – $0.3 billion, EEP – US$2.1 billion). Tolls on the Canadian mainline will be fully adjusted for the actual capital cost of the expansion, while tolls on the U.S. mainline, held by EEP, will be adjusted for approximately 88% of the actual cost.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty to Superior generally within or alongside Enbridge's existing right-of way. The Alberta Clipper Project will interconnect with the existing mainline system in Superior where it will provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing.

In the second quarter of 2007, Enbridge filed an application with the NEB to construct the 1,607-kilometre (1,000-mile) crude oil pipeline. The application includes a commercial settlement which sets out the tolling principles and risk and return parameters agreed to with shippers. The NEB hearings into the application concluded in the fourth quarter of 2007, and Enbridge expects a decision in the first quarter of 2008. Enbridge's affiliate EEP plans to file a similar application and set of toll principles with the FERC for the United States portion of the Alberta Clipper project. Subject to regulatory approval, Enbridge anticipates bringing Alberta Clipper into service in mid-2010. The project will have an initial capacity of 450,000 bpd, is expandable to 800,000 bpd and will form part of the existing Enbridge System in Canada and the EEP Lakehead System in the United States. Engineering, construction planning and procurement activities continue.

The Canadian segment of the line is expected to cost $2.0 billion (2007 dollars, excluding AFUDC) and the U.S. segment, to be undertaken by EEP, is expected to cost US$1.0 billion (2007 dollars, excluding capitalized interest). Enbridge will share in cost overruns or savings against estimates, for costs deemed to be controllable costs. Controllable costs comprise approximately 70% of the total cost estimate.

Line 4 Extension Project

In the second quarter of 2007, Enbridge filed a regulatory application with the NEB for the construction and operation of the $0.3 billion Line 4 Extension project. NEB hearings into the application were completed in January 2008 and a decision is expected in the second quarter of 2008. Subject to regulatory approvals, the project, involving construction of 136 kilometres (85 miles) of 36-inch diameter pipe to connect three existing 48-inch loops on the mainline system between Edmonton and Hardisty, would begin construction in 2008 and is expected to be in service in early 2009. Procurement of long lead items and detailed engineering for the pipeline and stations is proceeding.

3. Enhance Diluent Supply

Increasing heavy oil production in Alberta requires new supplies of diluent, which is needed to dilute heavy oils for transport through pipelines. The Company is developing projects to bring diluent to Alberta from the U.S. Midwest as well as imported diluent supplies from the west coast of British Columbia, as described in the Gateway Project.

Southern Lights Pipeline

When completed, the 180,000 bpd, 20-inch diameter Southern Lights pipeline will transport diluent from Chicago to Edmonton. During the first quarter of 2007, Enbridge filed for regulatory approval of the Canadian portion of the Southern Lights pipeline with the NEB, having obtained long-term commitments from shippers in 2006. In the fourth quarter of 2007, the Company completed the NEB oral hearing for the Canadian portion of the pipeline project. Enbridge received NEB approval in the first quarter of 2008. In the United States, various federal and state regulatory processes and related hearings are continuing. In concert with the Southern Access project, construction activities are nearly complete on the 321-mile (517-kilometre) section from Superior to Delavan, Wisconsin with over 95% of welding completed. The diluent line is expected to be in service in late 2010.

The Southern Lights Pipeline project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline which runs from Edmonton to Clearbrook, Minnesota. In order to replace the light crude capacity that would be lost through the reversal of Line 13, the Southern Lights Project also includes the construction of a new 20-inch diameter crude oil pipeline from Cromer, Manitoba to Clearbrook, and modifications to existing Line 2. These changes to the existing crude oil system will ultimately increase southbound light crude system capacity by approximately 45,000 bpd.

Based on construction costs experienced on the initial phase of the project, the expected capital cost has been updated to an estimated US$2.2 billion (including AFUDC). Based on this level of costs, the project will earn a minimum return on equity of 10% plus a premium return which depends on the extent to which throughput on the line exceeds 90% of capacity.

4. Develop New Market Access

The Company is developing new options for expanding market access for Canadian crude oil. Specific initiatives include: extending the mainline south of Chicago to Patoka, Illinois; expansion of the Spearhead Pipeline from Chicago to Cushing; developing access to the U.S. Gulf Coast through a combination of existing infrastructure and new pipelines; and developing access to markets in Asia and California with the Gateway Project.

Southern Access Extension Project

The Southern Access Extension involves the construction of a new 36-inch diameter, 400,000 bpd pipeline extending the mainline from Flanagan to Patoka, Illinois at a cost of approximately US$0.5 billion to Enbridge.

A FERC Offer of Settlement, filed in September 2006, proposing a rolled in toll design, was not approved by the FERC. The revised tolling methodology application for the Southern Access Extension Project was filed with the FERC in October 2007 and a decision is expected in the first quarter of 2008. Subject to regulatory approval, tolls will be fully adjusted for the actual capital cost of the project and construction would begin in 2008 with an estimated in-service date of 2009.

Spearhead Pipeline Expansion

This expansion, to be effected through additional pumping stations, will increase capacity from Chicago, Illinois to Cushing, Oklahoma by 65,000 bpd to 190,000 bpd. The expansion is expected to cost US$0.1 billion and to be completed in early 2009.

The Company successfully completed the Spearhead Pipeline Expansion Open Season in the second quarter of 2007 and received FERC approval of its toll filing in December 2007. Of the 65,000 bpd increased capacity, 30,000 bpd was committed to new shippers. The remaining 35,000 bpd capacity is available for spot shippers unless the committed shippers exercise their preferential right to a portion of this capacity. Preliminary engineering design has been completed for this project and construction is scheduled to commence in early 2008.

Texas Access Pipeline

In December 2007, Enbridge and ExxonMobil Pipeline Company announced the two companies will conduct a Solicitation for Binding Shipper Commitment (Open Season) for the proposed Texas Access Pipeline. The proposed Texas Access Pipeline will transport crude oil sourced from the Canadian oil sands region in Alberta and from the upper U.S Midwest to the Texas Gulf Coast. The proposed project includes a new 768-mile (1,236-kilometre), 30-inch diameter pipeline with a capacity of approximately 450,000 bpd, which will extend from Patoka, Illinois southward to Nederland, Texas. Also proposed is an 88-mile (142-kilometre), 24-inch pipeline with a capacity of approximately 180,000 bpd to transport crude oil onward from Nederland to the Houston, Texas area. The Open Season is to determine shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Open Season will guide and determine the further development of the proposed joint venture pipeline project.

Eastern PADD II / Eastern Canada

Enbridge is exploring options to provide incremental pipeline capacity to this market. Development of this project is ongoing and would be completed in stages, with up to approximately 100,000 bpd of incremental volume added by 2010. Additional access initiative discussions have commenced with area refiners to provide incremental infrastructure in the Eastern PADD II area for service in the 2013 timeframe.

Gateway Project

The Gateway Project includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat. The condensate line is expected to have a 20-inch diameter and an initial capacity of 193,000 bpd. The petroleum export line would have a 36-inch diameter and an initial capacity of 525,000 bpd. Capital cost estimates will be completed once commercial terms are finalized. Enbridge has secured third party funding support to advance the regulatory process. Subject to continued commercial support, regulatory and other approvals, the Company estimates that the Gateway in-service date will be in the 2012 to 2014 timeframe.

5. Develop Terminaling and Tankage Infrastructure

Based on producer interest, the Company is increasing its investment in contract terminals. Upstream contract tankage projects include the Hardisty Terminal, the Stonefell Terminal near Fort Saskatchewan and expansion of the Athabasca Terminal. Downstream projects are under development or consideration by Enbridge or EEP at Flanagan, Patoka, Cushing and the U.S. Gulf Coast. The Company and EEP are also constructing significant additions to the capacity of the common carrier mainline terminals at Edmonton, Superior and Chicago.

Hardisty Terminal

Enbridge is building a $0.4 billion crude oil terminal at Hardisty with a tankage capacity of 7.5 million barrels. Enbridge has executed contracts for 100% of the capacity and it is expected that the terminal will be completed in phases from late 2008 through 2009. Civil construction of the 19 tank pads was completed at the end of September 2007 and tankage construction is underway, with 30% complete at year-end. Once complete, the Hardisty Terminal will be one of the largest crude oil terminals in North America.

Stonefell Terminal

BA Energy Inc. is building a bitumen upgrader near Fort Saskatchewan, Alberta for which Enbridge has agreed to provide pipeline and terminaling services. Based on initial scope and cost estimates, Enbridge expects to invest approximately $0.1 billion in new facilities to provide tankage services at a new satellite terminal to be developed adjacent to the upgrader. Enbridge will also provide pipeline transportation for the upgrader's output from the new terminal to a refinery hub near Edmonton.

Construction is approximately 50% complete on the six tanks and ancillary facilities that comprise the Enbridge terminal facilities being constructed for BA Energy. BA Energy has recently delayed the in-service date of their upgrader until the second quarter of 2009. As a result, construction has been slowed until the in-service date of the upgrader is clear and to further secure coverage of Enbridge's costs.

The Stonefell Terminal is strategically located adjacent to several other proposed or operating upgrading facilities and pipeline systems and will be a focus for further development of contract terminaling infrastructure.

CAPITAL EXPENDITURES

In 2007, the Liquids Pipelines segment spent \$151 million on capital maintenance and improvements compared with an expected \$150 million. In 2008, the Company expects to spend \$150 million on capital maintenance and improvements.

Total expenditures for organic growth projects described above were \$1.3 billion for 2007, in line with expectations. For 2008, the Company expects to spend \$2.8 billion for the organic growth projects. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

LEGAL PROCEEDING

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced a class action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. The Plaintiffs filed a motion to establish a cause of action, which is one of the requirements to have the motion certified as a class action under the *Class Proceedings Act* (Ontario). The motion was dismissed by the Ontario District Court in late 2006. The Plaintiff appealed the decision and the appeal was heard by the Ontario Court of Appeal on December 18, 2007. The decision of the Court of Appeal has not been released. Since the outcome is indeterminable, the Company has made no provision at this time for any potential liability.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under Risk Management.

Supply and Demand

The operation of the Company's liquids pipelines depend on the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, depends on a number of variables, including the availability and cost of capital and labour for oil sands projects, the price of natural gas used for steam production and the price of crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing, alternative energy sources and global supply disruptions.

Alberta Royalty Review

On October 25, 2007, the Alberta government issued "The New Royalty Framework" report summarizing upcoming changes to the Alberta Royalty Program. The new Framework is effective January 2009 and involves increasing royalty rates and rate caps for conventional oil, natural gas and oil sands to adjust to fluctuating oil prices. This Framework could create economic hurdles for future oil sands development, which may affect the pace of future growth in volumes expected to flow through Enbridge's Liquids Pipelines Systems. As outlined in Enbridge's submission to the Royalty Review Panel, Enbridge shares its customers' need to ensure that Alberta remains a competitive business environment with a stable, positive and predictable investment climate. Enbridge is reviewing the government's proposed changes to the royalty regime and will be working closely with customers to better understand the implications of those changes.

ITS Metrics

The ITS governing the Enbridge System measures the Company's performance in areas key to customer service. If the Company fails to meet the baseline targets set out in the ITS for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $30 million in each of 2008 and 2009.

Potential Pressure Restrictions

The Company's liquids pipelines systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of the pipeline is indefinitely long; however, as the pipelines age the level of expenditures required for inspection and maintenance may increase. Temporary pressure restrictions have been established on some sections of some pipelines pending completion of specific inspection and repair programs. Pressure restrictions may from time to time be established on other of the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughout if and when the full capacity of that line segment would otherwise have been utilized. Pressure restrictions to date have not given rise to any loss of throughput. While the Enbridge System is volume-protected, EEP's Lakehead System would be adversely affected by pressure restrictions that reduce volumes transported. Additionally, on the Enbridge System ITS metrics penalties may apply if available capacity is reduced below baseline targets.

Regulation

The Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from these operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity, which is 8.71% in 2008 (2007 – 8.46%). To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS and Terrace Agreement, which govern the majority of the segment's assets.

Competition

Competition among common carrier pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other common carriers are available to producers to ship Western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition could also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. One such proposal is the Keystone Project sponsored by TransCanada Corporation to ship Western Canadian crude oil into PADD II starting in 2009. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls and multiple delivery and storage points. Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system. The Company's existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. The ITS and the Terrace Agreement on the Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection on its existing system but will on the Southern Access and Alberta Clipper expansions.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

GAS PIPELINES

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in the U.S. portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising Enbridge Offshore Pipelines (Offshore).

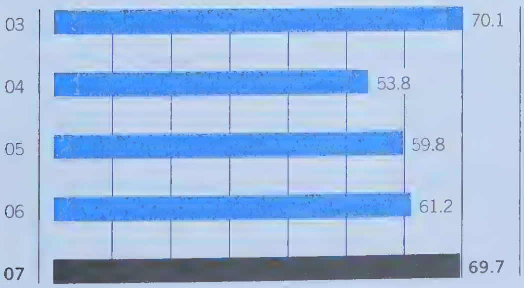
EARNINGS

(millions of dollars)	**2007**	2006	2005
Alliance Pipeline US	**27.7**	29.7	32.1
Vector Pipeline	**14.9**	13.4	15.9
Enbridge Offshore Pipelines	**27.1**	18.1	11.8
	69.7	61.2	59.8

Earnings from Gas Pipelines were $69.7 million for the year ended December 31, 2007 compared with $61.2 million for the year ended December 31, 2006. Earnings improved as construction of the Neptune Pipelines was completed and stand-by fees were earned starting in the fourth quarter. Also, Offshore received insurance proceeds in the second quarter of 2007 related to the 2005 hurricanes.

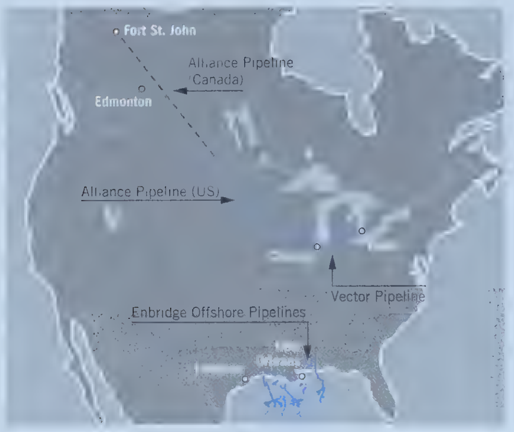
Earnings from Gas Pipelines were $61.2 million for the year ended December 31, 2006 compared with $59.8 million for the year ended December 31, 2005. The increase was due to improved results at Enbridge Offshore Pipelines in 2006, following two severe hurricanes in 2005. The increase was partially offset by the effects of the weaker U.S. dollar.

Revenues for the year ended December 31, 2007 were $321.3 million compared with $345.9 million for the year ended December 31, 2006. The decrease in revenues was substantially due to the effect of the stronger Canadian dollar. Revenues for the year ended December 31, 2006 were $345.9 million, consistent with $364.3 million for the year ended December 31, 2005.



Gas Pipelines Earnings
(millions of dollars)

Gas Pipelines earnings improved in 2007 as construction of the Neptune Pipelines was completed and stand-by fees were earned starting in the fourth quarter. Also, Offshore received insurance proceeds in the second quarter of 2007 related to the 2005 hurricanes.



Gas Pipelines

ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to Channahon, Illinois. The pipeline has firm service shipping contract capacity to deliver 1.325 billion cubic feet per day (bcf/d). EIF, described under Sponsored Investments, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with Aux Sable, a natural gas liquids extraction facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the Midwestern and Northeastern United States and Eastern Canada. Enbridge owns 42.7% of Aux Sable and its results are included under Gas Distribution and Services.

Results of Operations

Alliance Pipeline earnings were $27.7 million for the year ended December 31, 2007 compared with $29.7 million for the year ended December 31, 2006. The decrease was primarily due to the stronger Canadian dollar and the depreciating ratebase. The $2.4 million decrease in earnings between the year ended December 31, 2005 and 2006 was also primarily due to the stronger Canadian dollar.

Transportation Contracts

Alliance has long-term take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed return on equity. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. Alliance Pipeline US operations are regulated by the FERC.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense in the financial statements is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the financial statement amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, that is expected to be recovered from shippers in subsequent years. As at December 31, 2007, $143.7 million (2006 – $159.8 million) was recorded as deferred transportation revenue.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.2 bcf/d and is operating at or near capacity.

Vector Pipeline's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. Approximately 58% of the long haul capacity of Vector Pipeline is committed to long-term, 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service.

Results of Operations

Vector Pipeline earnings were $14.9 million for the year ended December 31, 2007 compared with $13.4 million for the year ended December 31, 2006. Vector Pipelines earnings improved, despite the stronger Canadian dollar, due to its late year expansion and lower operating costs in 2007.

Vector Pipeline earnings of $13.4 million for the year ended December 31, 2006 were $2.5 million lower than earnings of $15.9 million for the year ended December 31, 2005. The decrease reflected the stronger Canadian dollar and higher operating costs in 2006 due to scheduled integrity inspections required by the regulator within the first six years of operation.

Strategy

The Gas Pipelines strategy is developed based on the Company's forecast supply and demand for natural gas.

Supply and Demand for Natural Gas

Robust supply transported to the Chicago market is anticipated as a result of increasing conventional production in the Rocky Mountains, unconventional mid-continent production and new production from Gulf Coast LNG facilities. Surplus gas in Chicago will result in greater deliveries to the Ontario market as traditional exports from Western Canada are expected to decline. The development of oil sands projects in Alberta increases the demand for natural gas, as various extraction and upgrading processes require the use of natural gas; however, growth in this sector may be tempered by alternative energy sources. Over time, the entry of new supply from North Texas, the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as LNG are expected to adequately supply the market and provide opportunities for Enbridge to deliver this natural gas to markets.

Alliance Pipeline Recontracting

Transportation agreements on Alliance Pipeline US expire in 2015. Alliance Pipeline US is developing strategies to maximize its competitiveness, post-2015, in light of falling export production from Western Canada and the potential for surplus export pipeline capacity. In the longer term, Alliance is well placed to benefit from incremental volumes from Northern gas.

Vector Pipeline Expansion

The US$0.1 billion construction of two additional compressor stations was completed and put in service in the fourth quarter of 2007. These stations expand the pipeline's capacity from 1 bcf/d to 1.2 bcf/d. Vector secured 10-year firm transportation contracts for the new capacity.

Business Risks

The risks identified below are specific to Alliance Pipeline US and Vector Pipeline. General risks that affect the entire Company are described under Risk Management.

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending to 2015. Vector Pipeline's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll.

Exposure to Shippers

The failure of shippers to perform their contractual obligations could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet tariff requirements. These pipelines also have diverse groups of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US' competitive position.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts for approximately 58% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US operations are regulated by the FERC. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

Alberta Royalty Review

The Alberta Royalty Review as described under Liquids Pipelines is also applicable to both Vector Pipeline and Alliance Pipeline US.

ENBRIDGE OFFSHORE PIPELINES

Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 1,500 miles (2,400 kilometres) of underwater pipe and onshore facilities and transported approximately 2.1 bcf/d during 2007.

Results of Operations

Offshore earnings for the year ended December 31, 2007 were $27.1 million compared with $18.1 million for the year ended December 31, 2006. In 2007, earnings included $11.3 million of insurance proceeds for both property insurance recoveries and business interruption resulting from the 2005 hurricanes. The final insurance claim settlement is expected in the first half of 2008. Offshore earnings also reflected the impact of a stronger Canadian dollar, continuing repair and inspection costs and expected continuing natural production declines on deliveries to the pipelines in 2007. Start up issues experienced by producers on key production platforms, resulting from the effects of the extreme 2005 hurricane season, delayed new sources of volumes during the year; however, volumes from the Atlantis platform started contributing to earnings at the end of 2007.

Earnings for the year ended December 31, 2006 in Enbridge Offshore Pipelines were $18.1 million compared with $11.8 million for the year ended December 31, 2005. In 2006, volumes increased, resulting in increased earnings compared with 2005 which reflected the impact of two severe hurricanes. The 2006 results were negatively impacted by the stronger Canadian dollar.

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the lease's maximum sustainable production.

The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria but also provide the shippers with flexibility given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

Strategy

Offshore intends to grow through leveraging its existing asset position to attract new prospects including producer tie-backs as well as those requiring new laterals to be constructed by Offshore. A number of new discoveries exist in deepwater and the ultra-deep areas of the Gulf of Mexico in the corridors where Offshore has existing pipeline facilities. Offshore is continually monitoring and pursuing these prospects. Projects under construction are described below.

Neptune Pipelines Project

The Neptune natural gas lateral and crude oil lateral will connect the deepwater Neptune oil and gas field in the Green Canyon Corridor to existing Gulf of Mexico pipelines, extending Enbridge's existing Gulf

of Mexico infrastructure. Except for the final subsea connections, construction of the US$0.1 billion 26-mile (42-kilometre), 20-inch diameter oil pipeline with capacity of 60,000 bpd and 26-mile (42-kilometre), 12-inch diameter gas pipeline, with capacity of 0.2 bcf/d, was completed in the fourth quarter of 2007. The Company started collecting standby fees in fourth quarter 2007 and production volumes are expected to commence in early 2008.

Shenzi Project

Enbridge has substantially completed constructing a natural gas lateral to connect the new deepwater Shenzi field to existing Gulf of Mexico pipelines. The US$45.0 million 11-mile (18-kilometre), 12-inch diameter gas pipeline has capacity of 0.1 bcf/d. In-service continues to be scheduled for mid-2009, concurrent with producer first volumes. The Shenzi lateral will deliver natural gas through the Company's 22%-owned Cleopatra Pipeline, the 50%-owned Manta Ray Pipeline and the 50%-owned Nautilus Pipeline.

Atlantis and Thunder Horse Production Projects

Both of these significant third party-owned projects, which will deliver natural gas into Offshore's gathering systems, have experienced startup delays due to the severe 2005 hurricanes. Atlantis, a significant source of new volumes, was placed into service in December 2007 and volumes will continue to ramp up into early 2008. The operator of the Thunder Horse project expects it to be in service in the fourth quarter of 2008.

Business Risks

The risks identified below are specific to Enbridge Offshore Pipelines. General risks that affect the Company as a whole are described under Risk Management.

Weather

Adverse weather, such as hurricanes, may impact Offshore financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput and inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and refineries that may decrease throughput on Offshore systems.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage. However costs have increased in the form of higher insurance premiums and deductibles as well as longer waiting periods for business interruption claims. It is expected the incidence and severity of windstorm occurrences, and the Company's direct experience in the Gulf of Mexico, will dictate future costs and coverage levels in this region.

Competition

There is significant competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities and extend its footprint, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining production, as demonstrated with the newly constructed Neptune crude oil lateral. Given rates of decline, Offshore Pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates may be subject to challenge.

Other Risks

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners and through cost of service tolling arrangements. Start-up delays are mitigated by the right to collect stand-by fees.

CAPITAL EXPENDITURES

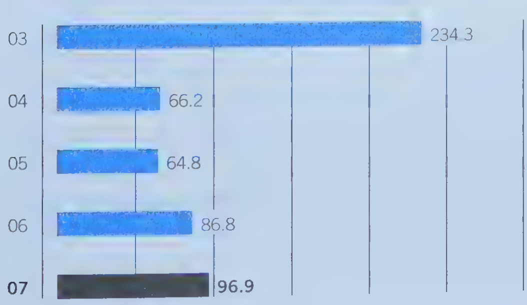
The Company expects to spend approximately $49 million in 2008 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2007, the Company spent $200 million on capital expenditures in the Gas Pipelines segment which is consistent with expectations. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 15.1% ownership interest in EEP and a 41.9% voting interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

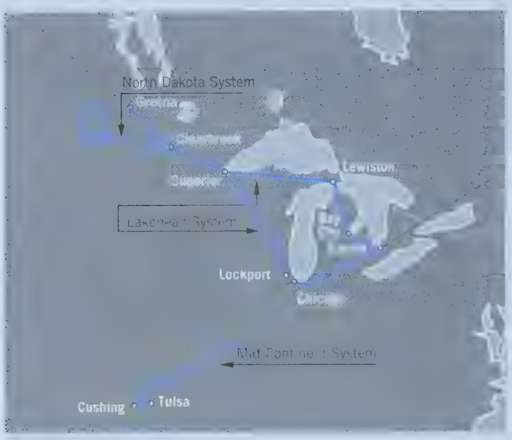
EARNINGS

(millions of dollars)	**2007**	2006	2005
Enbridge Energy Partners	**44.0**	43.0	21.7
Enbridge Income Fund	**39.2**	37.8	34.2
Dilution gains	**11.8**	–	8.9
Impact of tax changes	**1.9**	6.0	–
	96.9	86.8	64.8



Sponsored Investments Earnings
(millions of dollars)

Increased earnings from Sponsored Investments in 2007 were primarily a result of the recognition of a dilution gain on a unit issuance in which the Company did not participate.



Enbridge Energy Partners – Liquids Pipelines

Earnings from Sponsored Investments were $96.9 million for the year ended December 31, 2007 compared with $86.8 million in 2006. The increase in earnings was primarily a result of the recognition of a dilution gain on a unit issuance in EEP in which the Company did not participate.

Revenues from Sponsored Investments include only revenues from EIF as the Company equity accounts for its interest in EEP. For the year ended December 31, 2007, revenues were $270.3 million compared with revenues of $254.7 million for the year ended December 31, 2006. The $15.6 million increase in revenue was a result of increased tolls on the Alliance and Saskatchewan Systems as well as a full year contribution from the wind assets purchased in Q4-2006. Fiscal 2006 revenues of $254.7 million were relatively consistent with revenues of $249.0 million for the year ended December 31, 2005.

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the U.S., natural gas gathering and processing assets in Texas, the mid-continent crude oil system, various interstate and intrastate natural gas pipelines and a crude oil feeder pipeline in North Dakota.

Results of Operations

Earnings from EEP were $44.0 million for the year ended December 31, 2007, consistent with $43.0 million for the year ended December 31, 2006 despite the stronger Canadian dollar. Earnings for fiscal 2007, after adjusting for unrealized derivative fair value gains and losses (losses in 2007 of $6.3 million; gains in 2006 of $6.5 million) and Enbridge's $3.0 million share of the gain on the sale of Kansas Pipeline Company, increased $10.8 million compared to fiscal 2006. The increase reflects Enbridge's larger average ownership interest in 2007 as well as higher incentive income, increased processing margins and higher volumes on principal natural gas and liquids systems that were partially offset by higher operating expenses.

In 2005 EEP issued Class A partnership units which Enbridge did not fully participate in resulting in dilution gains. While new Class C units were issued by EEP in the third quarter of 2006 no dilution gains resulted as Enbridge participated in the offering, increasing Enbridge's ownership interest in EEP from 10.9% to 16.6%. Enbridge's average ownership interest in 2006 was 13.0%. In the second quarter of 2007, EEP issued partnership units. Because Enbridge did not fully participate in these offerings, dilution gains of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%. Enbridge's average ownership interest in 2007 was 15.5%.

Earnings from EEP were $43.0 million for the year ended December 31, 2006 compared with $21.7 million for the year ended December 31, 2005. The results improved significantly, despite the stronger Canadian dollar, and reflected considerably higher liquids throughput on the Lakehead System, higher margins and increased volumes in the natural gas gathering and processing businesses in addition to a higher Enbridge ownership interest. The 2006 results also included $6.5 million (net to Enbridge) of unrealized mark-to-market gains (2005 – $5.0 million of losses) on derivative financial instruments that did not qualify for hedge accounting treatment. While Enbridge believes the hedging strategies are sound economic hedging techniques, they do not qualify for hedge accounting and have been accounted for on a mark-to-market basis through earnings.

Enbridge Energy Partners – Gas Pipelines

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income, on the portion of cash distributions, on a per unit basis, that exceed certain target thresholds as follows:

	Unitholders including Enbridge	Enbridge GP Interest
Quarterly Cash Distributions per Unit:		
up to $0.59 per unit	98%	2%
first target – $0.59 per unit up to $0.70 per unit	85%	15%
second target – $0.70 per unit up to $0.99 per unit	75%	25%
over second target – cash distributions greater than $0.99 per unit	50%	50%

During the first three quarters of 2007, EEP paid quarterly distributions of $0.925 per unit (2006 – $0.925 per unit; 2005 – $0.925 per unit). Effective November 2007, EEP increased quarterly distributions to $0.95 per unit. Of the $44.0 million Enbridge recognized as earnings from EEP during 2007, 43% (2006 – 37%; 2005 – 65%) were incentive earnings while 57% (2006 – 63%; 2005 – 35%) were Enbridge's share of EEP's earnings.

Line 3 Incident

In November 2007, an unexpected release and fire on Line 3 of the Lakehead System occurred during planned maintenance near Enbridge's Clearbrook, Minnesota terminal, which resulted in fatalities of two Enbridge employees working on the Line. All pipelines in the vicinity were immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and repair of the pipeline at an estimated economic cost of US$2.6 million to EEP. Lines 1, 2 and 4 were restarted the following day after inspections revealed these lines had not been damaged. The volume of oil released was approximately 325 barrels, which was largely contained in the trench that had been excavated to

facilitate the planned maintenance. Excavation and repairs were completed and the line was returned to service within 5 days. EEP is now working with federal and state environmental and pipeline safety regulators to investigate the cause of the incident.

Strategy

EEP intends to increase its distributions primarily through the optimization of existing assets including increased throughput and the expansion of the existing liquids and gas midstream businesses, and potentially through the acquisition of complementary assets.

EEP is benefiting from strong supply growth in both the liquids transportation and gas midstream businesses. Oil sands volume growth will increase throughput and generate opportunities such as the Southern Access and Alberta Clipper expansions, described under Liquids Pipelines. Growing gas infrastructure needs, as a result of production growth and improved technology, are driving new capital investment and volume growth in EEP's principal gas regions. Tightening gas quality specifications are also increasing demand for EEP's treating and processing services. EEP's growing base of gas volumes has allowed it to aggregate volumes to improve margins and develop new take-away pipeline capacity projects.

In addition to the projects described under Liquids Pipelines, EEP is undertaking the following projects:

East Texas System Expansion and Extension (Project Clarity)

Project Clarity includes the construction of a 36-inch diameter pipeline to interstate and intrastate markets. This project is adding 0.7 bcf/d capacity to the current East Texas infrastructure. All phases of the project are complete with the exception of the Kountze, Texas to Orange, Texas stage which is expected to be completed in the first quarter of 2008. Additional capacity to downstream interconnects will increase as compression is added in mid-2008. When complete, the Clarity project will link growing natural gas production and third party storage assets in East Texas with major third party pipelines and markets in the Beaumont, Texas area.

North Dakota System Expansion

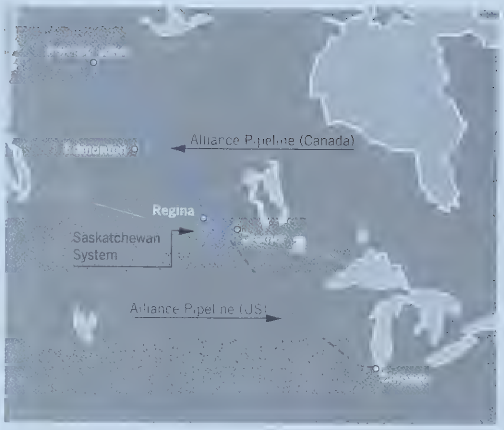
EEP is undertaking a further US$0.2 billion expansion of the Enbridge North Dakota Pipeline System. The expansion, if fully subscribed, is expected to increase system capacity from 110,000 bpd to 161,000 bpd by the end of 2009 and will consist of upgrades to existing pump stations, additional tankage as well as extensive use of drag reducing agents that are injected into the pipeline to increase throughput. The commercial structure for this expansion is a cost of service based surcharge that will be added to the existing tariff rates. Subject to approval from the FERC, this expansion is expected to be completed in early 2010.

Business Risks

Supply and Demand

The profitability of EEP depends to a large extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of Western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and Eastern Canada. EEP expects significantly increased crude oil supplies from the oil sands projects in Alberta. In addition, Enbridge's future plans to provide access to new markets in the Southern United States are expected to increase demand for Western Canadian crude oil, resulting in increased volumes for EEP.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer owned gathering systems.



Enbridge Income Fund

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP are subject to regulation by the FERC or state regulators and their revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and NGLs. Historically, these risks have been managed by using physical and financial contracts, fixing the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to associated mark-to-market valuation changes.

ENBRIDGE INCOME FUND

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of the Alliance System described in the Gas Pipelines segment above. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in Southern Saskatchewan and Southwestern Manitoba connecting primarily with Enbridge's mainline pipeline to the United States.

EIF also owns interests in three wind power generation projects purchased from Enbridge in October, 2006 and a business that develops and operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Results of Operations

Earnings from EIF were $39.2 million for the year ended December 31, 2007, comparable with the prior year of $37.8 million.

In 2007, EIF recognized future taxes within entities that will become taxable in 2011 as a result of the enactment of Bill C-52, which is discussed under Tax Fairness Plan. This future tax increase was more than offset by the revaluation of future income tax obligations previously recorded as a result of tax rate reductions in the second and fourth quarters of 2007.

Earnings from EIF were $37.8 million for the year ended December 31, 2006, comparable with the prior year, and reflected modest earnings growth at EIF driven by lower tax on distributions received from EIF.

Tax Fairness Plan

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax of 29.5% will be imposed on Enbridge Income Fund starting in 2011, provided EIF limits its expansion to "normal growth" prior to 2011. The impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers in the future. As enacted in its present form, the Tax Fairness Plan will, all other things being equal, likely result in a reduction of cash available for distribution by EIF commencing in 2011. With respect to the limitations on normal growth, the Company believes the Fund should be able to fund its currently identified growth plans within the constraints of the "normal growth" rule.

Incentive and Management Fees

Enbridge receives a base annual management fee of $0.1 million for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2007, the Company received incentive fees of $3.5 million (2006 – $2.4 million, 2005 – $2.1 million). The Company is the primary beneficiary of EIF through a combination of the voting units and a non-voting preferred unit investment and as such EIF is consolidated under variable interest entity accounting rules.

Strategy

EIF will maximize the efficiency and profitability of its existing assets, pursue organic growth and expansion opportunities, invest in the expansion activities within its assets including the Saskatchewan System expansion and Alliance Canada receipt facilities expansion as well as three new waste heat power generation projects.

Business Risks

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines segment.

Saskatchewan System

The majority of the volumes shipped on the Saskatchewan and Westspur common carrier pipeline systems, key components of the Saskatchewan System, have no specific volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls; however, there is limited pipeline competition in this area. The main competition to the pipelines is from trucking.

EIF's liquids and natural gas pipelines are dependent upon the supply of and demand for crude oil and natural gas from Western Canada.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses.

EARNINGS

(millions of dollars)	**2007**	2006	2005
Enbridge Gas Distribution	**128.8**	61.8	111.9
Noverco	**18.6**	22.7	28.3
Enbridge Gas New Brunswick	**12.1**	9.8	6.1
Other Gas Distribution	**7.3**	6.5	6.7
Energy Services[1]	**3.6**	10.1	5.0
Aux Sable	**(17.5)**	25.8	5.3
Other[1]	**3.5**	12.6	15.5
Impact of tax changes	**27.7**	28.9	–
	184.1	178.2	178.8

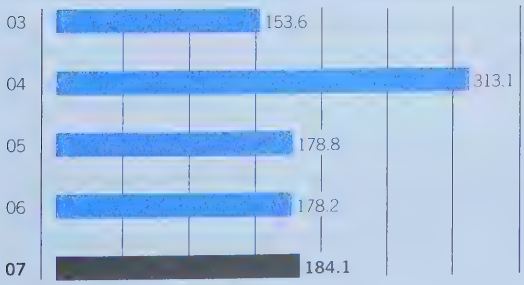
1 *Tidal Energy's results have been reclassified from Other to Energy Services for all periods presented. Other now includes earnings from CustomerWorks.*

Earnings were $184.1 million for the year ended December 31, 2007 compared with $178.2 million for the year ended December 31, 2006. Increased earnings were due to colder than normal weather in 2007 compared with significantly warmer than normal weather in 2006 as well as customer growth in 2007. These increases were partially offset by derivative losses at Aux Sable and lower contributions from the Energy Services businesses.

Earnings were $178.2 million for the year ended December 31, 2006 compared with $178.8 million for the year ended December 31, 2005. Earnings were comparable with 2005, reflecting a number of offsetting factors including higher earnings from Aux Sable due to upside sharing of positive fractionation margins and lower earnings from EGD resulting from both warmer than normal weather and a lower allowed rate of return on common equity.

Revenues for the year ended December 31, 2007 were $10,227.1 million compared with $8,981.6 million for the year ended December 31, 2006. The increase in revenues was a result of a significant increase in volumes transacted by Tidal Energy and, to a lesser extent, an increase in commodity prices for those transactions.

Revenues for the year ended December 31, 2006 were $8,981.6 million compared with $6,947.1 million for the year ended December 31, 2005. The factors contributing to this increase were Tidal Energy commencing U.S. operations in December 2005, resulting in a full year of revenues in 2006, as well as Tidal Energy earning higher revenues due to a higher average price of crude oil in 2006 and EGD's revenues increasing over 2005 as gas prices were high in Q1 of 2006 when the greatest sales volumes were generated.



Gas Distribution and Services Earnings
(millions of dollars)

Gas Distribution and Services earnings in 2007 reflected colder than normal weather in 2007 compared with significantly warmer than normal weather in 2006 as well as customer growth in 2007. These increases were partially offset by derivative losses in Aux Sable and lower contributions from the Energy Services businesses.

Gas Distribution and Services

ENBRIDGE GAS DISTRIBUTION

EGD is a rate-regulated natural gas distribution utility serving customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas as well as the Niagara Peninsula, Ottawa and many other Ontario communities. EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.8 million customers in central and eastern Ontario, Southwestern Quebec and parts of Northern New York State. EGD's operations in Ontario are regulated by the Ontario Energy Board (OEB).

Results of Operations

Earnings for the year ended December 31, 2007 were $128.8 million compared with $61.8 million and $111.9 million for the years ended December 31, 2006 and 2005, respectively. Weather changes over the past three years were the major factor in the earnings fluctuations. In 2007, weather was colder than normal resulting in increased earnings, whereas in 2006 weather was warmer than normal which resulted in lower earnings compared with 2005 when the weather was considered relatively normal.

Earnings in 2007 also increased compared with 2006 because of customer growth, higher operating margins and benefits earned for exceeding targets in the promotion of energy efficient use of natural gas. The decrease in earnings between 2006 and 2005 was also a result of a lower allowed rate of return on common equity, partially offset by a higher rate base.

Normal weather is the weather forecast by EGD in the Toronto area using the forecasting methodology approved by the OEB. Determination of normal weather may also be based on a negotiated settlement with the interveners as part of the regulatory process. This financial measure is unique to EGD and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized factors that may be identified by other companies. Moreover, normal weather may not be comparable year-to-year given that the forecasting models are updated annually.

As part of its 2007 rate application, EGD requested a change in the methodology used to calculate normal weather to a 20-year trend method, which is a better predictor of weather. In its decision released on July 5, 2007, the OEB approved the proposed 20-year trend method for calculating normal weather in EGD's main franchise area, the Greater Toronto Area. As a result, the effect of 2007 weather was calculated retroactively to January 1, 2007, based on the approved method, which corresponds to normal weather of 3,617 annual degree days.

Incentive Regulation

Improving the regulatory environment is one of the key strategic thrusts to provide greater operational and organizational flexibility. EGD remained in a cost of service methodology environment in 2007, but will change to Incentive Regulation (IR) methodology in 2008, with 2007 as the base year for a potential

five year plan. Under IR, rates are set based on a formulaic approach, using the base year rates as the starting point for the IR plan term.

The objectives of the IR plan are as follows:

- reduce regulatory costs with less frequent hearings – under normal circumstances, every five years – rather than every year under cost of service;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

Rate Application for the IR Term Starting 2008

On February 11, 2008, the OEB approved the Settlement Agreement (the Settlement) filed by EGD which reflected negotiations with ratepayer representatives regarding the type of IR methodology as well as the applicable terms and conditions. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive).

EGD's rate application requested a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The application also requested that revenue per customer be calculated by increasing the prior year's revenue by inflation and reducing it by a productivity challenge factor which would motivate EGD to increase productivity. Revenue could also include specific categories of expenses to enable EGD to recover cost increases beyond management's control.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the cost of service methodology used in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, EGD will have the opportunity to benefit from productivity enhancements and incremental revenues.

The key terms of the Settlement are summarized as follows:

Revenue per Customer Cap – The Settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize EGD's exposure to declining average use of natural gas while providing incentive for EGD to continue growing its customer base.

Earnings Sharing – To align the interests of customers with EGD, an earnings sharing mechanism forms part of the Settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e. excluding the effects of weather) (ROE) exceeds a notional allowed utility rate of return on equity (NROE) by certain prescribed thresholds, the excess will be shared with customers.

Adjustments – The Settlement provides for the recovery of capital invested in new power generation laterals. EGD is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

Off Ramps – An OEB review will be triggered if EGD's ROE varies more than 300 basis points (either negatively or positively) relative to the NROE.

EGD applied for and, on December 18, 2007, was granted approval for interim rates effective January 1, 2008 and expects the OEB's final 2008 rate order will be applied retroactively to January 1, 2008.

2007 and 2006 Rates

The key elements of the 2007 and 2006 decisions are summarized below:

Regulatory year	Approved 2007	Approved 2006
Rate base *(millions of Canadian dollars)*	$3,745.7	$3,633.6
Deemed common equity for regulatory purposes	36%	35%
Rate of return on common equity	8.39%	8.74%

The OEB released its final decision relating to EGD's 2007 cost of service rate application on July 5, 2007. The new rates approved by the OEB's decision resulted in an overall increase in rates of approximately 3.5% for the average residential customer. EGD was granted a 1% increase in the equity component of its deemed capital structure to 36% from 35% reflecting changes in EGD's business risk environment and financial risk position. In addition, the new 20-year trend method to calculate normal weather was approved. Finally, EGD was directed to cease its risk management program, which utilized price swaps, calls and collars to manage the volatility in the price of natural gas. Consistent with prior years, changes in the price of natural gas flow through to the customer.

EGD's 2007 and 2006 rates were established pursuant to a cost of service methodology that allowed revenues to be set to recover EGD's forecast costs. Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, income taxes, and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in gas distribution, storage and transmission as well as an allowance for working capital. Under the cost of service model, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs.

The rate base is financed through a combination of debt and equity. For the debt portion, interest expense incurred by EGD is recovered in rates. For the equity portion, the OEB sets the rate of return that EGD may recover in rates. The allowed rate of return on equity for EGD is based on the forecast yield on Canadian government long-term bonds.

Effects of Rate Regulation

As EGD is subject to rate-regulation, either in a cost of service or incentive model, there are circumstances where revenues recognized do not match the amounts billed. Certain amounts are deferred for recovery or refund with the approval of the regulator and are not included in revenues or expenses that would otherwise be recognized in the income statement, in the absence of rate regulation.

The regulator allows certain variances between approved and actual expenses to be recovered from, or refunded to, customers in future periods. The deferred amounts are not included in the calculation of rates billed to customers. While there are numerous deferral accounts approved by the regulator, the difference between the price of gas approved by the regulator and the actual cost of gas purchased is the most significant. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved cost of gas and the related revenue rather than the actual cost of gas and related revenue. EGD has no exposure to changes in the cost of gas as it is a flow through cost that is passed to the ratepayer.

Strategy

EGD's vision is to be North America's leading energy distribution and services company. To achieve this vision, EGD has outlined the following strategic objectives:

- focus on safety, operational excellence and customer satisfaction;

- grow core utility earnings;
- improve return on invested capital; and
- develop human resources.

One of EGD's major strategic initiatives is to evaluate the potential changes of the regulatory environment in planning and maximizing future operational and organizational flexibility. EGD has continued regulatory filings through the cost of service process for 2007 to ensure an appropriate base is in place for a 2008 IR plan. At the same time, EGD plans to transform the business for IR, including rationalizing capital investment, increasing productivity and identifying top line enhancements while maintaining system reliability and safety.

Customer Growth

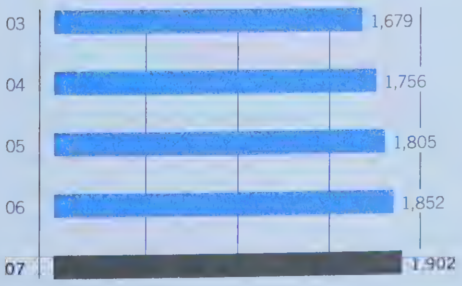
Another major strategic initiative is enhancing customer growth. EGD added over 43,000 new customers in the year ended December 31, 2007 (over 47,000 in the year ended December 31, 2006). EGD expects to add 40,000 to 45,000 customers in 2008. In addition to traditional gas distribution growth expected, new earnings growth opportunities include investment in new laterals for power generation, fuel switching, implementation of turboexpanders on the gas distribution system, development and delivery of energy efficiency programs and billing services for third parties as well as development of new gas load balancing options.

Storage Project

In April 2007, EGD signed storage contracts to provide daily services totaling 2.8 million gigajoules, or approximately 2.6 billion cubic feet (bcf), of storage capacity, including 10 or 20-day storage service with firm year-round withdrawal and injection levels. Based on a final OEB decision to cease regulating prices for new storage services offered, EGD will proceed with development of the project.

Customer Care and Customer Information System Agreements

In April 2007, EGD entered into five-year customer care services contracts with third party service providers for meter reading, billing, billing administration, call handling and collections. The total cost of the contracts is approximately $274 million over the five year term. EGD is planning to have a new CIS system in service by July 2009 to meet regulatory requirements and to meet the need for a more robust and technologically up-to-date system. The OEB has approved a six-year rate recovery arrangement for the customer care services and a ten-year recovery of the $119 million in capital to be invested in the new CIS.



Gas Distribution and Services – Number of Active Customers

(thousands)

EGD added over 43,000 new customers in 2007 and EGD expects to add 40,000 to 45,000 customers in 2008. The 2004 number reflects the 15-month period reported as part of Enbridge's change in financial reporting to eliminate consolidation of gas distribution operations on a quarter lag basis.

Capital Expenditures

EGD's capital expenditures in recent years have averaged approximately $300 million per year, but are expected to increase in 2008 to $407 million as EGD completes laterals for new power generating facilities, and builds its CIS system discussed above.

Legal Proceedings

Bloor Street Incident

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. Although a timetable for the appeal has not yet been set by the Court, the Company expects that it will be heard during 2008. The maximum possible fine upon conviction on all charges would be approximately $5.0 million in the aggregate.

EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The majority of the civil actions have been settled and EGD does not expect the outstanding civil actions to result in any material financial impact.

Harper Gardens Incident

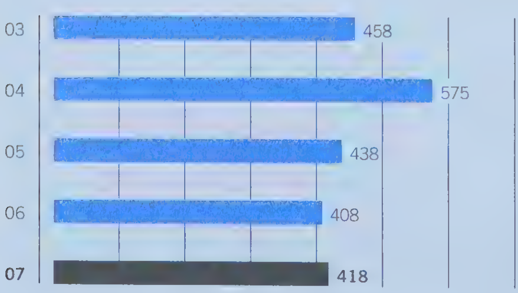
In February 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A gas fitter in the home at the time of the explosion was seriously burned. Several public authorities are investigating the incident. EGD has also been named as defendant in civil actions related to the explosion, but does not expect these actions to result in any material financial impact.

Business Risks

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under Risk Management.

Regulatory Risk

Through the regulatory process, the OEB approves the return on equity that EGD is allowed to include in rates, in addition to various other aspects of utility operations. The formula currently approved by the



Volume of Gas Distributed
(billion cubic feet)

Gas volumes distributed reflect the growing number of active customers and the impact each year of warmer than normal or colder than normal weather. The 2004 volumes reflects the 15-month period.

OEB for determination of the return on equity is based on the OEB's current risk assessment of EGD for the 2007 fiscal year and is effectively embedded into rates over the IR period.

EGD expects the implementation of certain factors in the IR formula will permit it to recover certain costs that are beyond management control, but are necessary for the maintenance of its services. Furthermore, EGD has requested a mechanism to end the IR plan and return to cost of service if there are significant and unanticipated developments (i.e., natural disasters, war, high rates of inflation, etc.) that threaten the sustainability of the IR plan. To the extent the OEB denies recovery of any such costs, EGD is at risk.

EGD does not profit from the sale of the natural gas commodity nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow it to recover or refund the natural gas commodity cost differential.

EGD has a quarterly rate adjustment mechanism in place for the natural gas commodity. This allows for the quarterly adjustment of rates to reflect changes in natural gas commodity prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on a volumetric basis, EGD's ability to collect its total revenue requirement depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts will be reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing or competitive energy sources and the growth of customers.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 78% (2006 – 77%) of total distribution volume. Weather during the year, measured in degree days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating. In 2007, the winter months were colder than forecast, resulting in a favourable weather related volume variance of 11.6 bcf.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies along with more efficient building construction that continues to place downward pressure on annual average consumption. Average annual residential gas usage has declined by 1.3% per annum over the last 10 years, reflecting consistent customer conservation efforts.

Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volumes distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

Franchise Rights

EGD has an exclusive right to serve all end users within its franchise area, under its franchise agreements. Similar franchise agreements in adjacent areas are held by peer companies such as Union Gas Limited (UGL). On January 6, 2006, the OEB granted Greenfield Energy Corporation, a potential power-plant customer of UGL, the right to physically bypass UGL's distribution network within UGL's franchise area, in order to serve its own power-plant. The OEB's decision to not uphold exclusive franchise rights of a local distribution utility in Ontario was unprecedented. However, the OEB characterized this decision as transitional, and set up a rates proceeding which assessed the service requirements of gas fired generation in the province of Ontario. The OEB decision from this rates proceeding was issued in November 2006. EGD believes the new rates are robust and would make physical bypass of EGD's system unattractive to gas fired power generation plants. However, the OEB decision did not preclude any party from seeking approval from the OEB to build its own pipeline and bypass the local distribution utility. EGD objects strongly to the concept that any such franchise violation is acceptable and will object if any similar proposal arises in the EGD franchise area.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro also has a 50% interest in TQM Pipeline, which transports natural gas in Quebec, and is partnering with the Company on the Rabaska LNG project (described under Other Natural Gas Distribution Strategies below). Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings elimination adjustments at Enbridge.

Results of Operations

Noverco earnings were $18.6 million for the year ended December 31, 2007 compared with $22.7 million for the year ended December 31, 2006. The $4.1 million decrease in earnings is a result of the recognition of a $4.0 million dilution gain in 2006 from a Gaz Metro unit issuance in which Noverco did not participate.

Noverco earnings were $22.7 million for the year ended December 31, 2006 compared with $28.3 million for the year ended December 31, 2005. Earnings decreased due to a $7.3 million dilution gain in 2005, which resulted from a Gaz Metro unit issuance in which Noverco did not participate, compared with a dilution gain of $4.0 million in 2006. Excluding dilution gains, earnings from Noverco were lower in 2006 as 2005 included a future income tax recovery stemming from the receipt of a significant cash dividend.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

ENBRIDGE GAS NEW BRUNSWICK

The Company owns 70.8% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 8,200 customers. Approximately 645 kilometres (400 miles) of distribution main has been installed with the capability of attaching approximately 29,000 customers.

Results of Operations

EGNB earnings were $12.1 million for the year ended December 31, 2007 compared with $9.8 million for the year ended December 31, 2006. Earnings were higher in 2007 due to the impact of the increasing ratebase.

EGNB earnings were $9.8 million for the year ended December 31, 2006 compared with $6.1 million for the year ended December 31, 2005. Earnings were higher in 2006 as debt was settled through the issuance of equity during the third and fourth quarters of 2005 resulting in a higher equity base throughout 2006.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB has approved the deferral of the difference between distribution revenues and the cost of service during the development period for recovery in future rates. This recovery period is expected to start in 2010 and end no sooner than December 31, 2040. On December 31, 2007, the regulatory deferral asset was $117.7 million (2006 – $101.8 million).

ENERGY SERVICES

Energy Services includes Gas Services and Tidal Energy, the Company's energy marketing businesses.

Gas Services markets natural gas to optimize Enbridge's commitments on the Alliance and Vector Pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to transportation capacity. Capacity commitments as of December 31, 2007 were 32.2 mmcf/d on the Alliance Pipeline (2.0% of total capacity) and 162.1 mmcf/d on Vector Pipeline (16.4% of total capacity). Capacity commitments as of December 31, 2006 were 31.6 mmcf/d on the Alliance Pipeline (2.4% of total capacity) and 159.2 mmcf/d on Vector Pipeline (15.9% of total capacity).

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance Pipeline, and between Chicago and Dawn, for Vector Pipeline. To the extent the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing risk management pricing options. Tidal Energy's business involves buying, selling and storing large quantities of crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities, physical receipt or delivery shortfalls can create modest commodity exposures. Any open positions created from this physical business are tightly monitored by, and must comply with, the Company's formal risk management policies.

Results of Operations

Earnings from Energy Services were $3.6 million for the year ended December 31, 2007 compared with $10.1 million for the year ended December 31, 2006. The decrease in earnings is due to outstanding storage transactions in Tidal Energy that were negatively impacted by rising crude oil prices. Tidal

Energy buys crude oil, stores it and sells it forward at a higher price, locking in a profit on the transaction. However, during the life of the transaction, Tidal Energy may hold the oil held in storage and use it to satisfy a new forward sale at an additional deferred profit. Tidal Energy then purchases oil at spot prices to satisfy the original sale transaction. As a result, losses will be recognized in periods of rising oil prices and profitability will be deferred until the original transaction settles.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago. Aux Sable owns and operates a plant at the terminus of the Alliance System. The plant extracts NGLs from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGLs, or lower heat content, and to take advantage of positive commodity price spreads.

Aux Sable has an agreement with BP Products North America Inc. to sell its NGLs production to BP. In return, BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, commencing January 1, 2006 and may be extended by mutual agreement for 10-year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, although Aux Sable has the right to reduce such losses to avoid termination.

Results of Operations

Loss for the year ended December 31, 2007 was $17.5 million compared with earnings of $25.8 million for the year ended December 31, 2006. Aux Sable's 2007 reported earnings included $28.1 million of unrealized derivative fair value losses related to the Company's share of 2008 contingent upside sharing revenue. Upside sharing revenue is earned on natural gas processing margins in excess of certain thresholds. Derivative transactions used in 2007, and in place for 2008, provide cash flow predictability which is important to the Company in this period of significant project financing. The stronger Canadian dollar also resulted in a decrease in earnings in 2007.

Earnings for the year ended December 31, 2006 were $25.8 million compared with earnings of $5.3 million for the year ended December 31, 2005. Fractionation margins were very positive throughout 2006 and as a result, earnings from the upside sharing mechanism account for the majority of earnings from Aux Sable.

OTHER

Other earnings were $3.5 million in 2007 compared with earnings of $12.6 million in 2006. Other includes CustomerWorks which generated lower earnings in 2007 because, pursuant to an OEB recommendation, customer care services related to EGD were transitioned to a third party service provider.

Strategy

Other Natural Gas Distribution Strategies

Enbridge intends to pursue natural gas business development opportunities complementary to the existing gas distribution and services businesses through:

- developing LNG regasification projects and related pipeline infrastructure;
- pursuing marketing and storage opportunities that optimize existing assets; and
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. The approach is to slowly build this business and utilize partners to share development risks.

Further to this strategy, Enbridge is developing a number of projects, which are described below.

Rabaska LNG Facility

Enbridge, Gaz Metro and Gaz de France are continuing development of the $0.8 billion Rabaska LNG terminal to be located on the St. Lawrence River in Levis, Quebec. Environmental and marine applications have been reviewed by Federal and Provincial government agencies and positive reports issued. Provincial government project and land use approval was received in October 2007 and Federal approval is expected shortly. Discussions are in progress with potential LNG suppliers regarding long-term terminal use arrangements.

Ontario Wind Project

Enbridge is developing approximately 182 megawatts of wind power in the Municipality of Kincardine on the eastern shore of Lake Huron in Ontario. In July 2007, the Ontario Municipal Board and the Ontario Ministry of the Environment ruled in favour of the construction of Enbridge's Ontario Wind Project. This was the final approval required and subsequently construction has commenced with access roads, turbine foundations, electrical sub-station and utility transmission lines. On completion, the $0.5 billion project will be one of the largest wind power projects in Canada. Enbridge has entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all the power produced by the project.

The project is expected to begin producing electricity during the latter half of 2008 and be fully operational in early 2009.

Netthruput

In 2007, the Company and its partner in Netthruput (NTP) entered into an agreement with the TSX Group granting the TSX Group the option to purchase NTP, an internet-based crude oil trading and clearing platform. The Company received $9.5 million proceeds from the sale of the option, which may be exercised at a time after March 15, 2009 for a price between $40 million and $95 million depending on NTP's 2008 net earnings. The agreement also provides the Company and its partner in NTP an option to sell NTP under the same terms to the TSX Group. The Company has a 52% ownership interest in NTP.

CAPITAL EXPENDITURES

Capital expenditures in Gas Distribution and Services, excluding EGD, were $215 million in 2007 and are expected to be approximately $261 million in 2008.

INTERNATIONAL

International includes earnings from the Company's 25% interest in Compañia Logística de Hidrocarburos CLH, S.A. (CLH), Spain's largest refined products transportation and storage business, and its investment in, and management of, Oleoducto Central S.A. (OCENSA), a crude oil pipeline in Colombia. Other includes administration and business development.

EARNINGS

(millions of dollars)	**2007**	2006	2005
CLH	**65.6**	54.5	61.6
OCENSA/CITCol	**32.9**	33.9	32.8
Other	**(3.4)**	(5.2)	(7.0)
	95.1	83.2	87.4

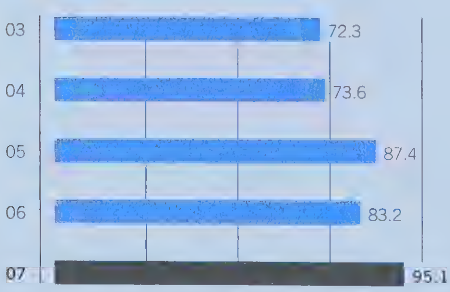
Earnings for the year ended December 31, 2007 were $95.1 million compared to $83.2 million for the year ended December 31, 2006. Earnings in 2007 included a $5.2 million gain on the sale of land within CLH. The increase in earnings was also due to stronger operating earnings in CLH as a result of higher transported volumes, an increase in operating revenues from complimentary businesses, lower income taxes as a result of a tax rate reduction in Spain and lower business development costs in Other.

Earnings for the year ended December 31, 2006 were $83.2 million compared with $87.4 million for the year ended December 31, 2005. Earnings from CLH for 2005 included a $7.6 million gain on the sale of land, recorded in the fourth quarter.

CLH

The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network located throughout Spain. Earnings are based on a fee for service tariff, adjusted annually for inflation, and are dependent on throughput volumes and storage levels.

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access, non-discriminatory basis. The system consists of over 3,400 kilometres (2,113 miles) of pipelines and 38 storage facilities located throughout the country. CLH provides refined product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships. CLH also provides long-term storage for strategic reserves of refined products to both operators and a Spanish Government Agency, CORES, which is responsible for



International Earnings
(millions of dollars)

International earnings in 2007 included a $5.2 million gain on the sale of land within CLH. Increased earnings were also due to stronger operating earnings in CLH.

managing the country's strategic hydrocarbon reserves. In addition, CLH offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, its participation in the aviation fuel business is expected to continue. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where most imports of crude oil and refined products into Spain are first delivered.

Spain – CLH

Earnings from CLH are directly impacted by the demand for refined products, including gasoline, diesel, jet fuel and other transportation fuels. Economic growth in Spain over the last decade has been among the highest in the European Union, which has led to increasing demand for energy, including refined products. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH is in the process of expanding its system over the next several years in order to meet the continued growth expected in this region and to deliver incremental volumes expected from domestic refinery expansions, located primarily in the south of the country. This expansion, which includes an increase in storage capacity and looping of both the northern and southern main lines, is being constructed in phases to match the expected growth in volumes.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, an investment on which the Company earns a fixed return. OCENSA is one of two main crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages the pipeline and earns a fee for this service, which includes incentives for operating performance. In 2007, OCENSA made the final payments with respect to its original US$1.6 billion project debt financing. With no further debt servicing obligations OCENSA may opt to begin returning the Company's initial equity capital starting in 2009, in accordance with the terms of the project agreements.

STRATEGY

The Company will de-emphasize the pursuit of new acquisition opportunities outside of North America, due to the competitive environment and the significant number of opportunities available in the North American liquids business. On February 13, 2008, Enbridge announced it is evaluating strategic alternatives for monetizing its investment in CLH. Proceeds from any monetization of the CLH investment would be applied toward funding the Company's growth projects.

Colombia – OCENSA

BUSINESS RISKS

The International business is subject to risks related to political and economic instability, currency volatility, market and supply volatility, government regulations, foreign investment rules, security of assets and environmental considerations. The Company assesses and monitors international regions and specific countries on an ongoing basis for changes in these risks. Risks are mitigated by a combination of Enbridge's governance involvement, contractual arrangements, influence in operation of the assets, regular analysis of country risk as well as foreign currency hedging and insurance programs.

CORPORATE

(millions of dollars)	**2007**	2006	2005
Corporate	**(63.0)**	(82.2)	(63.9)
Impact of tax changes	**30.2**	14.0	–
	(32.8)	(68.2)	(63.9)

The Corporate segment includes corporate financing costs, corporate development activities and other corporate costs not attributable to a specific business segment.

Corporate costs totaled $32.8 million for the year ended December 31, 2007, compared with $68.2 million in 2006. After adjusting for the impact of favorable legislated tax changes, Corporate costs decreased $19.2 million due to lower interest expense resulting from decreased average debt balances throughout 2007 as a result of the equity issuance in the first quarter. As well, expenditures on corporate development activity decreased because of the Company's focus on organic growth.

Corporate costs were $68.2 million for the year ended December 31, 2006 compared with $63.9 million for the year ended December 31, 2005. The increase in Corporate costs was due to a number of factors including higher interest expense as a portion of the Company's floating rate debt was repaid through the issuance of long-term fixed rate debt as well as higher business development activity and the impact of a strong labour market on compensation expense.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to generate sufficient cash from operations and debt issuances to fund liabilities as they become due, finance budgeted investing activity and pay common share dividends throughout 2008. Additional liquidity, if necessary, is available under committed credit facilities or through access to the capital markets. At December 31, 2007, the Company had $5.6 billion (2006 – $3.3 billion) of committed credit facilities, of which $2.4 billion was drawn or used to backstop commercial paper. On January 4, 2008, a new credit facility was arranged for general corporate purposes and to fund the

construction of organic growth projects, such as Alberta Clipper Pipeline. The addition of this facility increased the Company's credit facilities to $6.6 billion subsequent to year-end.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2007, including short-term borrowings, but excluding non-recourse short and long-term debt, strengthened to 62.7%, compared with 64.6% at the end of 2006 and 66.5%, compared with 68.6% at the end of 2006 including non-recourse debt.

The Company's current liabilities routinely exceed current assets. Current liabilities include current maturities of long-term debt, which are typically refinanced with long-term debt. Excluding current maturities of long-term debt, the Company does not have a working capital deficit.

OPERATING ACTIVITIES

Cash from operating activities increased to $1,378.7 million for the year ended December 31, 2007 from $1,297.7 million for the year ended December 31, 2006 and $947.0 million for the year ended December 31, 2005.

(millions of dollars)	**2007**	2006	2005
Earnings net of non-cash items	**1,358.0**	1,171.0	1,300.9
Changes in operating assets and liabilities	**20.7**	126.7	(353.9)
Cash Provided by Operating Activities	**1,378.7**	1,297.7	947.0

Cash provided by earnings net of non-cash items, was $1,358.0 million for the year ended December 31, 2007, compared with $1,171.0 million and $1,300.9 million for 2006 and 2005, respectively. The increased earnings from operating activities resulted primarily from higher earnings at EGD due to colder than normal weather in 2007.

Changes in operating assets and liabilities generated $20.7 million in 2007, compared with $126.7 million in the prior year. This decrease primarily resulted from increased accounts receivable at EGD at December 31, 2007 due to the relatively colder weather experienced during the final billing periods of the year. Changes in operating assets and liabilities were $480.6 million higher in 2006 compared with 2005. The increase was due primarily to the impact of a declining trend in the price of natural gas in the latter half of 2006 compared with an increasing trend in 2005.

INVESTING ACTIVITIES

Cash used for investing activities for the year ended December 31, 2007 was $2,255.9 million compared with $1,580.0 million in 2006. In 2007, the Company had increased capital expenditures, primarily due to growth projects such as Southern Lights, the Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge System. There were no acquisitions in the current year.

In 2006, the Company spent $1,580.0 million on investing activities compared with $876.5 million in 2005, an increase of $703.5 million. The majority of the increase was due to expenditures on property, plant and equipment, including the commencement of capital expenditures on a number of Liquids Pipelines projects. In addition, $381.6 million of the increase resulted from the investment in EEP and the acquisition of an interest in Olympic Pipeline.

FINANCING ACTIVITIES

In 2007, the Company generated $904.2 million through financing activities compared with $268.1 million in 2006 and cash used for financing activities of $22.1 million in 2005. This increase in cash flow from financing activities is primarily a result of the equity issuance and drawing on the new Southern Lights credit facility, which are discussed below.

Financing activities in 2007 included the issuance of US$400.0 million of long-term debt in the first quarter, US$650.0 million in the second quarter and issuance of $200.0 million of medium-term notes in the fourth quarter. These financing activities were used to refinance long-term debt maturities and to finance new growth projects at attractive long-term interest rates.

Short-term borrowings at EGD are used primarily to finance working capital, including inventory. Short-term debt financing increased in 2007 primarily to finance new growth projects offset by a decrease in short term debt at EGD as a result of lower working capital requirements.

In 2007 the Company expanded its available liquidity through credit facility expansions and additions. Specifically, the Company increased the size of the existing facilities by $1.9 billion. On August 31, 2007, a new US$500.0 million credit facility with a 364-day term was arranged to fund project costs directly related to the Southern Lights Project.

During 2006, the Company issued $1,125.0 million of new long-term debt (2005 – $1,020.1 million) in the form of medium-term notes and repaid $400.0 million in medium-term notes which matured during 2006. EGD's short-term borrowings were $266.9 million lower in 2006 compared with 2005, reflecting the impact of decreasing natural gas prices. This decrease in short-term borrowings was partially offset by an increase in short-term debt to finance capital expenditures and investments.

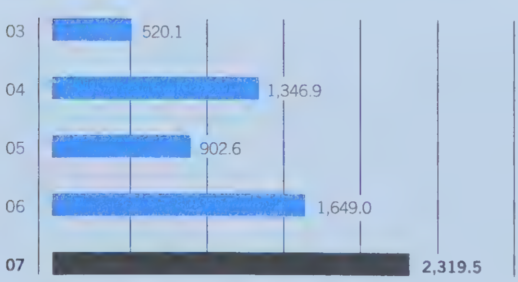
Dividends on common shares increased again in 2007 due to an increased number of common shares outstanding and a higher dividend rate.

Equity Issuance

On February 2, 2007, Enbridge closed the issuance of 13.5 million common shares for $38.75 per share to the public and issued 1.5 million common shares to Noverco for $38.75 per share, which maintains Noverco's ownership interest in Enbridge at approximately 9.5%. Net proceeds from both offerings totaled $566.4 million.

Preferred Securities

The Company redeemed its $200.0 million, 7.8% Preferred Securities on February 15, 2007.



Capital Expenditures, Investments and Acquisitions
(millions of dollars)

The 2007 total for capital expenditures, investments and acquisitions reflects increased capital expenditures primarily due to growth projects such as Southern Lights, the Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge Systems.

Expected Capital Expenditures

The numerous organic growth projects and other growth initiatives described in the business unit sections will require capital funding. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3.7 billion during 2008 on capital projects and maintenance. The Company expects to finance these expenditures through cash from operating activities and additional external financing. The Company may also raise capital through the monetization or disposition of selected businesses. Enbridge announced February 13, 2008 that the Company is evaluating strategic alternatives for monetizing its investment in CLH.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued to finance business acquisitions, investments in subsidiaries and long-term investments.

Funds for debt retirements are generated through cash provided from operating activities as well as through the issue of replacement debt.

Payments due for contractual obligations over the next five years and thereafter are as follows:

(millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt[1]	8,318.3	604.5	1,054.3	400.0	6,259.5
Non-recourse long-term debt[1]	1,524.7	59.5	340.1	181.3	943.8
Capital and operating leases	166.2	12.1	27.1	28.7	98.3
Long term contracts[2,3]	2,505.8	935.9	900.4	381.9	287.6
Total Contractual Obligations	12,515.0	1,612.0	2,321.9	991.9	7,589.2

1 *Excludes interest component.*
2 *Approximately $947.6 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects.*
3 *Contracts totaling $252.0 million are with proportionately consolidated joint venture entities.*

SENSITIVITY ANALYSIS

The Company's earnings will fluctuate with changes in certain market prices, volumetric throughput and with weather.

Enbridge quantifies and manages its market price risks using an earnings at risk (EaR) metric. Under the Company's EaR policy, the maximum adverse change in the 12 month forward earnings forecast (due to movements in market prices over a one-month period of time) will not exceed 5% of earnings (based on a 95% confidence interval). On December 31, 2007, the Company's EaR was 2.8% (2006 – 2.9%) of 12 month forecasted earnings.

The following table shows the effect that changes in certain key financial market variables has on earnings. These sensitivities are approximations based on business conditions as of December 31, 2007 and may not be applicable to other periods.

Factor	Change	After-Tax Earnings Impact
Exchange rate (CAD Dollar to U.S. Dollar)	CAD$0.01	$1.5 million
Exchange rate (CAD Dollar to euro)	CAD$0.01	$0.4 million
Interest rate	0.5%	$3.0 million

Interest rate fluctuations are captured in the Company's EaR metric; however, under GAAP the impact of foreign currency fluctuations on earnings from foreign subsidiaries cannot be hedged. As such, these fluctuations have been excluded from the Company's EaR metric. The Company does hedge the foreign currency risk on cash distributions it receives from foreign currency denominated subsidiaries. Unhedged foreign currency cash flows are incorporated in the EaR metric.

Transportation volumetric risks are managed through tariff agreements. Most of the Company's tariff agreements provide for take-or-pay or throughput insensitivity.

Weather is a significant driver of delivery volumes at EGD, given that a significant portion of EGD's customers use natural gas for space heating. Weather, measured in terms of degree day deficiency, directly impacts EGD's earnings as noted below. Degree-day is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	17 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.2 million (after-tax)

In recent years weather has impacted earnings by a larger magnitude than the above sensitivities would suggest. This results from the unusual pattern of distribution of degree days during the year and their relative effectiveness. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

RISK MANAGEMENT

The Company's business activities are subject to execution, financing, market price, credit and operating risks. The Company has formal risk management policies, processes and systems designed to mitigate these risks.

EXECUTION RISK

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third party opposition, government approvals, cost escalations, construction delays and shortages (collectively Execution Risk). The Company's significant growth plans may strain its resources and are subject to high cost pressures that prevail in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, crown consultation, environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages due to the overheated energy sector may impact project development. Labour shortages, inexperience and productivity issues may also affect the successful completion of the projects.

The Company has a clearly defined management and governance structure for all major projects. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements. The Company's emphasis on corporate social responsibility promotes positive relationships with landowners, aboriginal groups and governments. Cost tracking and centralized purchasing is used on all major projects. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel. In early 2008, the Company made changes in its senior management team structure which further emphasize successful project execution.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt and equity to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and U.S. debt and equity market conditions can change dramatically, affecting capital availability.

To address this risk, the Company ensures that it can readily access either the Canadian or U.S. public capital markets by maintaining current shelf prospectuses with the securities regulators. In addition, the Company maintains sufficient liquidity through committed credit facilities with its banking groups which would enable the Company to fund all anticipated requirements for one year without accessing the capital markets.

MARKET PRICE RISK

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively Market Price Risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Board of Directors approved Market Price Risk Policy to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance. The Market Price Risk metric utilized within that policy is EaR, described above under Sensitivity Analysis.

The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed and the financial derivative hedging programs implemented.

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and euro denominated investments, where both carrying values and earnings are subject to foreign exchange rate vulnerability. Furthermore, the Company is exposed to foreign exchange rate variability on the conversion of the foreign currency denominated cash flows back to Canadian dollars (the "economic exposure"). The Company has a hedging policy to eliminate 50% to 70% of the long-term economic exposure related to its foreign currency denominated cash flows. It will also hedge shorter term anticipated foreign currency capital expenditures.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on the cost of variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors approved policy limit band of up to 25% floating rate debt as a percentage of total debt outstanding. Fixed to floating swaps are also used from time to time to manage this position and optimize the Company's debt portfolio. The Company is also exposed to fluctuations in interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into interest rate derivatives to hedge a portion of the interest cost of these future debt issues.

Information about the debt portfolio is included in Notes 12 and 13 of the Company's Consolidated Financial Statements for the year ended December 31, 2007.

Commodity Price Risk

The Company uses natural gas price swaps, futures and options to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector Pipelines. The Company also uses natural gas, power, crude oil and NGLs derivative instruments to fix the value of variable price exposures that arise from commodity usage, storage, transportation and supply agreements.

Fair Values of Derivative Instruments

Information about the financial instruments (including derivatives) outstanding at year end is included in Note 18 of the Company's Consolidated Financial Statements for the year ended December 31, 2007.

CREDIT RISK

Entering into derivative financial instruments can give rise to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. Overall credit exposure limits have been set in the Board of Directors approved Credit Policy.

The Company minimizes credit risk by entering into risk management transactions only with institutions that possess high investment grade credit ratings or have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral.

Credit risk also arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process.

OPERATING RISKS

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company's pipelines or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks.

Regulation

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers.

Environmental, Health and Safety Risk

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce. The Company could be targeted, along with the oil sands industry, by environmental groups to draw attention to greenhouse gas emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and company policy.

CRITICAL ACCOUNTING ESTIMATES

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2007 of $12,597.6 million, or 63% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the

integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments, except the Corporate segment. For certain rate regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates. Revised assumptions have historically resulted in extending useful lives.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the ERCB and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. As of December 31, 2007, the Company's regulatory assets totaled $548.4 million (2006 – $559.7 million) and regulatory liabilities totaled $173.7 million (2006 – $146.6 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits (OPEB) other than pensions to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. See Note 20 to the 2007 Annual Consolidated Financial Statements for disclosure of the difference between the actual and the expected results for the past two years. Pension expense is recorded within all of the Company's business segments.

(millions of dollars)	Pension Benefits		OPEB	
Impact of a 0.5% Change in Key Assumptions	Obligation	Expense	Obligation	Expense
Decrease in discount rate	78.3	10.2	14.8	1.3
Decrease in expected return on assets	n/a	5.7	n/a	0.2
Decrease in rate of salary increase	(19.2)	(4.3)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and

certain of the Company's subsidiaries and investments including Enbridge Gas Distribution Inc. and Enbridge Energy Company, Inc. are disclosed in Note 24 of the 2007 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The present value of expected future cash flows is determined using assumptions such as the probability of abandonment in place versus removal and the estimated costs required upon abandonment in each case, the discount rate and the estimated time to abandonment. For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing, the long-lived nature of the assets and the scope of the asset retirements. Changes in any of these assumptions could materially affect the asset and liability recognized in respect of asset retirement obligations as well as the resulting accretion of the liability and depreciation of the asset within any of the Company's business segments, with the exception of the Corporate segment.

CHANGE IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 *Comprehensive Income*, Section 3251 *Equity*, Section 3855 *Financial Instruments – Recognition and Measurement*, Section 3861 *Financial Instruments – Disclosure and Presentation* and Section 3865 *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in Accumulated Other Comprehensive Income or Loss.

The adoption of the new standards did not impact the Company's earnings or cash flows.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the valuation of the Company's financial instruments has not changed. The methods by which the Company determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars)

Increase/(Decrease)	Assets	Liabilities and Equity
Accounts Receivable and Other[1,2]	5.4	–
Deferred Amounts and Other Assets[1,2,3,4]	55.3	–
Long-Term Investments[1]	(57.3)	–
Accounts Payable and Other[2]	–	57.6
Long-Term Debt[3]	–	(52.7)
Other Long-Term Liabilities[1,2,4]	–	42.5
Future Income Taxes[1]	–	(18.9)
Non-Controlling Interest[1]	–	(26.3)
Accumulated Other Comprehensive Income[1]	–	48.2
Retained Earnings[1]	–	(47.0)
	3.4	3.4

1 *As a result of the new standards for cash flow hedges, the Company recognized unrealized net gains related to interest rate, foreign exchange and commodity hedges. The Company adjusted both deferred amounts and retained earnings for historical fair value adjustments related to certain cash flow hedges.*

2 *The Company recorded a regulatory liability due to the recognition of fixed price power contracts offset by unrealized financial instrument losses.*

3 *The Company reclassified unamortized deferred financing fees from deferred amounts and other assets to long-term debt as a result of adopting the new standards.*

4 *Relates to the recognition of gas purchase hedges for the regulated gas distribution businesses at January 1, 2007.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosure and Presentation

Effective January 1, 2008, the Company will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosure and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Company will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861 *Financial Instruments – Disclosure and Presentation*. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand discussion around the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date and how the entity manages those risks.

Inventories

The CICA issued Section 3031 *Inventories* effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS). This standard will not materially impact the Company's financial statements.

Rate Regulated Operations

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to rate regulated operations. The AcSB decided to retain much of the existing guidance related to

rate-regulated operations; however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465, *Income Taxes*, and the exemption from CICA Handbook Section 1100, *Generally Accepted Accounting Principles*, will be removed, effective January 1, 2009. The Company will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets.

International Financial Reporting Standards

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. Firms will begin reporting (with comparative data) under IFRS by the first quarter of 2011. While IFRS is based on a conceptual framework similar to Canadian GAAP, there are significant differences with respect to recognition, measurement and disclosures, which the Company is beginning to assess.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S securities law. As of the year ended December 31, 2007, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Enbridge Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rule of the United States Securities and Exchange Commission and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2007.

During the year ended December 31, 2007, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

QUARTERLY FINANCIAL INFORMATION[1]

(millions of dollars, except for per share amounts)

2007	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
Revenues	**3,358.2**	**2,728.7**	**2,634.0**	**3,198.5**	**11,919.4**
Earnings applicable to common shareholders	**227.0**	**146.5**	**78.1**	**248.6**	**700.2**
Earnings per common share	**0.65**	**0.41**	**0.22**	**0.70**	**1.97**
Diluted earnings per common share	**0.64**	**0.41**	**0.22**	**0.69**	**1.95**
Dividends per common share	**0.3075**	**0.3075**	**0.3075**	**0.3075**	**1.23**

(millions of dollars, except for per share amounts)

2006	Q1	Q2	Q3	Q4	Total
Revenues	3,346.7	2,327.2	2,184.9	2,785.7	10,644.5
Earnings applicable to common shareholders	190.9	157.9	95.5	171.1	615.4
Earnings per common share	0.56	0.47	0.28	0.50	1.81
Diluted earnings per common share	0.56	0.46	0.28	0.49	1.79
Dividends per common share	0.2875	0.2875	0.2875	0.2875	1.15

1 *Quarterly Financial Information has been extracted from financial statements prepared in accordance with generally accepted accounting principles.*

Revenue includes amounts billed to customers of EGD for natural gas, which varies with fluctuations in the commodity price. Higher natural gas commodity prices increase revenues, but would not similarly impact earnings, given the cost of natural gas flows through to customers. Fluctuations in commodity prices also impact revenues from Energy Services businesses.

In addition, revenue fluctuates due to the seasonality of EGD's business. Typically, revenue peaks in the winter months during the first quarter and, to a lesser extent, in the fourth quarter of the year when higher gas volumes are sold. Finally, EGD's revenue and earnings are affected by variations in the weather, especially in the winter, when warmer or colder than normal temperatures can result in lower or higher distribution volumes, respectively.

Significant items that impacted the quarterly earnings and revenue, in addition to the seasonal fluctuations described above, were as follows:

- Fourth quarter earnings in 2007 included the impact of tax changes, which increased consolidated earnings.
- Third quarter 2007 included a loss from Aux Sable.
- Second quarter 2007 included higher earnings from EGD due to colder than normal weather and a dilution gain in EEP.
- First quarter 2007 included higher earnings from EGD due to colder weather than the prior year period and the receipt of 2005 hurricane insurance proceeds.

- Fourth quarter earnings in 2006 reflected higher earnings from the Enbridge System and Aux Sable, offset by lower earnings from EGD due primarily to warmer than normal weather and higher costs.
- Third quarter earnings in 2006 reflected higher earnings from Enbridge System, increased earnings from the Company's investment in EEP and the recognition of upside sharing in Aux Sable.
- Second quarter earnings in 2006 included the impact of tax rate reductions, which increased consolidated earnings.
- First quarter earnings in 2006 reflected increased earnings in Enbridge System more than offset by lower results from EGD, due primarily to warmer than normal weather.

FOURTH QUARTER 2007 HIGHLIGHTS

Earnings applicable to common shareholders were $248.6 million, of $0.70 per share, for the three months ended December 31, 2007, compared with $171.1 million, or $0.50 per share, for the three months ended December 31, 2006. Significant factors that increased earnings included strong fourth quarter results from Enbridge System and EGD as well as tax changes enacted in the fourth quarter of 2007.

SELECTED ANNUAL INFORMATION

(millions of dollars, except per share amounts)	**2007**	2006	2005
Total Revenues	**11,919.4**	10,644.5	8,453.1
Dividends per Common Share	**1.2300**	1.1500	1.0375
Common Share Dividends	**452.3**	403.1	361.1
Total Assets	**19,907.4**	18,379.3	17,210.9
Total Long-Term Liabilities	**11,117.4**	10,544.8	9,690.7

Total assets and long-term liabilities increased from 2006 to 2007 because of investments in organic growth projects. The increase in total assets and total long-term liabilities from 2005 to 2006 was also a result of ongoing investments in core businesses as well as a $280 million investment in EEP, increasing the Company's interest from 10.9% to 16.6%.

OUTSTANDING SHARE DATA

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	368,690,996
Total issued and outstanding stock options (8,306,711 vested)	15,519,434

Outstanding share data information is provided as at February 20, 2008.

RELATED PARTY TRANSACTIONS

Information about the Company's related party transactions is included in Note 23 to the Company's consolidated financial statements for the year ended December 31, 2007.

Additional information relating to Enbridge, including the Annual Information Form, is available on www.sedar.com.

Dated February 20, 2008

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2007.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

Patrick D. Daniel
President & Chief Executive Officer

J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 20, 2008

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Enbridge Inc. as at December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enbridge Inc. as at December 31, 2007 and December 31, 2006, and the related consolidated statements of earnings, comprehensive income, shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2007 and for each of the years in the two year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exits, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2007 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 20, 2008

Comments by Auditors for U.S. Readers on Canada – U.S. Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in note 2 to the consolidated financial statements. Our report to the shareholders dated February 20, 2008 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the Independent Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 20, 2008

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of dollars, except per share amounts)

Year ended December 31,	**2007**	2006	2005
Revenues			
Commodity sales	**9,536.4**	8,264.5	6,193.5
Transportation	**2,115.5**	2,095.1	1,938.1
Energy services	**267.5**	284.9	321.5
	11,919.4	10,644.5	8,453.1
Expenses			
Commodity costs	**9,009.5**	7,824.6	5,728.4
Operating and administrative	**1,163.7**	1,084.2	1,057.6
Depreciation and amortization	**596.9**	587.4	575.3
	10,770.1	9,496.2	7,361.3
	1,149.3	1,148.3	1,091.8
Income from Equity Investments	**167.8**	180.3	116.8
Other Investment Income *(Note 21)*	**195.1**	107.8	142.4
Interest Expense *(Note 12)*	**(550.0)**	(567.1)	(539.2)
	962.2	869.3	811.8
Non-Controlling Interests	**(45.9)**	(54.7)	(27.6)
	916.3	814.6	784.2
Income Taxes *(Note 19)*	**(209.2)**	(192.3)	(221.3)
Earnings	**707.1**	622.3	562.9
Preferred Share Dividends	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**700.2**	615.4	556.0
Earnings per Common Share *(Note 15)*	**1.97**	1.81	1.65
Diluted Earnings per Common Share *(Note 15)*	**1.95**	1.79	1.63

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Earnings	**707.1**	622.3	562.9
Other Comprehensive Income/(Loss)			
Change in unrealized gains on cash flow hedges, net of tax	**96.4**	–	–
Reclassification to earnings of realized cash flow hedges, net of tax	**(6.7)**	–	–
Other comprehensive gain/(loss) from equity investees	**(19.8)**	–	–
Non-controlling interest in other comprehensive income	**4.9**	–	–
Change in foreign currency translation adjustment	**(447.1)**	87.6	(193.3)
Change in unrealized gains on net investment hedges, net of tax	**174.9**	(51.6)	161.3
Other Comprehensive Loss	**(197.4)**	36.0	(32.0)
Comprehensive Income *(Note 2)*	**509.7**	658.3	530.9

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Preferred Shares *(Note 15)*	**125.0**	125.0	125.0
Common Shares *(Note 15)*			
Balance at beginning of year	**2,416.1**	2,343.8	2,282.4
Common shares issued	**566.4**	–	6.8
Dividend reinvestment and share purchase plan	**17.7**	18.4	14.6
Shares issued on exercise of stock options	**26.3**	53.9	40.0
Balance at End of Year	**3,026.5**	2,416.1	2,343.8
Contributed Surplus			
Balance at beginning of year	**18.3**	10.0	5.4
Stock-based compensation	**8.9**	10.5	5.5
Options exercised	**(1.5)**	(2.2)	(0.9)
Balance at End of Year	**25.7**	18.3	10.0
Retained Earnings			
Balance at beginning of year	**2,322.7**	2,098.2	1,840.9
Earnings applicable to common shareholders	**700.2**	615.4	556.0
Cumulative impact of change in accounting policy *(Note 2)*	**(47.0)**	–	–
Dividend reclassification adjustment *(Note 8)*	**–**	–	51.2
Common share dividends	**(452.3)**	(403.1)	(361.1)
Dividends paid to reciprocal shareholder	**13.7**	12.2	11.2
Balance at End of Year	**2,537.3**	2,322.7	2,098.2
Accumulated Other Comprehensive Loss *(Note 17)*			
Balance at beginning of year	**(135.8)**	(171.8)	(139.8)
Cumulative impact of change in accounting policy *(Note 2)*	**48.2**	–	–
Other comprehensive (loss)/income	**(197.4)**	36.0	(32.0)
Balance at End of Year	**(285.0)**	(135.8)	(171.8)
Reciprocal Shareholding *(Note 8)*			
Balance at beginning of year	**(135.7)**	(135.7)	(135.7)
Participation in common shares issued	**(18.6)**	–	–
Balance at End of Year	**(154.3)**	(135.7)	(135.7)
Total Shareholders' Equity	**5,275.2**	4,610.6	4,269.5
Dividends Paid per Common Share	**1.2300**	1.1500	1.0375

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Operating Activities			
Earnings	**707.1**	622.3	562.9
Depreciation and amortization	**596.9**	587.4	575.3
Unrealized losses on derivative instruments	**32.3**	–	–
Equity earnings less than/(in excess of) cash distributions	**(35.2)**	(54.2)	63.3
Gain on reduction of ownership interest	**(33.9)**	–	(29.0)
Future income taxes	**40.8**	(21.0)	108.1
Non-controlling interests	**45.9**	54.7	27.6
Other	**4.1**	(18.2)	(7.3)
Changes in operating assets and liabilities *(Note 22)*	**20.7**	126.7	(353.9)
	1,378.7	1,297.7	947.0
Investing Activities			
Acquisitions *(Note 5)*	–	(101.4)	(88.6)
Long-term investments	**(20.3)**	(362.3)	(89.9)
Additions to property, plant and equipment	**(2,299.2)**	(1,185.3)	(724.1)
Affiliate loans, net	**15.6**	28.0	0.7
Change in construction payable	**48.0**	41.0	25.4
	(2,255.9)	(1,580.0)	(876.5)
Financing Activities			
Net change in short-term borrowings and short-term debt	**74.5**	(78.7)	(125.1)
Net change in non-recourse credit facilities	**43.1**	57.7	11.0
Long-term debt issues	**1,342.2**	1,125.0	1,020.1
Long-term debt repayments	**(634.5)**	(400.0)	(536.9)
Non-recourse long-term debt issues	**14.4**	2.8	6.8
Non-recourse long-term debt repayments	**(58.8)**	(60.5)	(85.1)
Contributions from/(distributions to) non-controlling interests	**(18.2)**	(31.3)	1.4
Common shares issued	**600.7**	63.1	53.7
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common share dividends	**(452.3)**	(403.1)	(361.1)
	904.2	268.1	(22.1)
Increase/(Decrease) in Cash and Cash Equivalents	**27.0**	(14.2)	48.4
Cash and Cash Equivalents at Beginning of Year	**139.7**	153.9	105.5
Cash and Cash Equivalents at End of Year	**166.7**	139.7	153.9

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of dollars) Year ended December 31,	**2007**	2006
Assets		
Current Assets		
Cash and cash equivalents	**166.7**	139.7
Accounts receivable and other	**2,388.7**	2,045.6
Inventory	**709.4**	868.9
	3,264.8	3,054.2
Property, Plant and Equipment, net *(Note 6)*	**12,597.6**	11,264.7
Long-Term Investments *(Note 8)*	**2,076.3**	2,299.4
Deferred Amounts and Other Assets *(Note 9)*	**1,182.0**	924.5
Intangible Assets *(Note 10)*	**212.0**	241.5
Goodwill *(Note 11)*	**388.0**	394.9
Future Income Taxes *(Note 19)*	**186.7**	200.1
	19,907.4	18,379.3
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings	**545.6**	807.9
Accounts payable and other	**2,213.8**	1,723.8
Interest payable	**89.1**	95.1
Current maturities of long-term debt *(Note 12)*	**605.2**	537.0
Current maturities of non-recourse debt *(Note 13)*	**61.1**	60.1
	3,514.8	3,223.9
Long-Term Debt *(Note 12)*	**7,729.0**	7,054.0
Non-Recourse Long-Term Debt *(Note 13)*	**1,508.4**	1,622.0
Other Long-Term Liabilities	**253.9**	91.1
Future Income Taxes *(Note 19)*	**975.6**	1,062.5
Non-Controlling Interests *(Note 14)*	**650.5**	715.2
	14,632.2	13,768.7
Shareholders' Equity		
Share capital		
Preferred shares *(Note 15)*	**125.0**	125.0
Common shares *(Note 15)*	**3,026.5**	2,416.1
Contributed surplus	**25.7**	18.3
Retained earnings	**2,537.3**	2,322.7
Accumulated other comprehensive loss *(Note 17)*	**(285.0)**	(135.8)
Reciprocal shareholding *(Note 8)*	**(154.3)**	(135.7)
	5,275.2	4,610.6
Commitments and Contingencies *(Note 24)*	**19,907.4**	18,379.3

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

David A. Arledge
Chair

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Sponsored Investments, Gas Distribution and Services and International. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines includes the Canadian common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons including the Enbridge System, the Athabasca System, Spearhead Pipeline and a proportionately consolidated investment in the Olympic Pipeline.

GAS PIPELINES

Gas Pipelines consists of proportionately consolidated investments in natural gas pipelines including the U.S. portion of the Alliance Pipeline, Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

SPONSORED INVESTMENTS

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP) and Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) as well as Enbridge Income Fund (EIF).

The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. EIF is a publicly traded income fund whose primary operations include a 50% interest in the Canadian portion of the Alliance Pipeline and a crude oil and liquids pipeline and gathering system.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of natural gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, and the Company's proportionately consolidated investment in Aux Sable, a natural gas fractionation and extraction business.

The Company's commodity marketing businesses are also included in Gas Distribution and Services. These businesses manage the Company's volume commitments on Alliance and Vector Pipelines as well as offer commodity storage, transport, and supply management services.

INTERNATIONAL

The Company's International business consists of investments in two energy-delivery businesses, Compañía Logística de Hidrocarburos CLH, S.A. (CLH) in Spain and Oleoducto Central S.A. (OCENSA) in Colombia.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 27. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the financial statements. Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the

Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as financial assets (see Financial Instruments). All long-term investments are assessed for impairment if the Company identifies an event indicative of possible impairment.

REGULATION

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta (ERCB), New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Company would capitalize only the interest component; therefore, the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, Enbridge Gas Distribution (EGD) capitalizes a percentage of certain operating costs into the rate base. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

Contributions made to the defined benefit pension plan for the regulated operations of Gas Distribution and Services are expensed as paid, consistent with the recovery of such costs in rates. Canadian GAAP requires pension costs and obligations for defined benefit pension plans to be determined using the projected benefit method and charged to earnings as services are rendered.

The cost of providing post-employment benefits other than pensions (OPEB) for the regulated operations of Gas Distribution and Services is expensed when paid, consistent with the recovery of such costs in rates.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed. Customer credit worthiness is assessed before agreements are signed. Certain operations are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts, resulting in the recognition of regulatory assets and liabilities.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of a committed 30-year delivery contract rather than the cash tolls received.

For rate-regulated operations in Gas Pipelines and Sponsored Investments, transportation revenues include amounts related to expenses recognized in the financial statements that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to receivable or payable balances.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulator. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. For the non-regulated portion of Gas Distribution and Services operations, delivery or service performance only takes place when there is a sales contract in place specifying delivery volumes or services required and sales prices.

FINANCIAL INSTRUMENTS

The Company classifies financial assets as either held for trading, held to maturity, loans and receivables or available for sale. The Company classifies financial liabilities as either held for trading or other financial liabilities.

Financial assets and liabilities that are "held for trading" are measured at fair value with changes in fair value recognized in earnings, except for derivatives that are designated as, and determined to be, effective hedging instruments, whose fair value is recorded in Other Comprehensive Income (OCI).

Financial assets that are "available for sale" are measured at fair value with changes in those fair values recorded in OCI. Financial assets that are "held to maturity" and "loans and receivables" and financial liabilities that are "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Other investments in entities which are not subsidiaries or joint ventures, and where the Company does not exercise significant influence, are classified as held to maturity, loans and receivables or available for sale. "Available for sale" investments are measured at fair value with changes in those fair values recorded in OCI. Where actively quoted prices are not available, these investments are carried at amortized cost. "Held to maturity" investments and "loans and receivables" are measured at amortized cost.

Cash and cash equivalents are designated as "held for trading" and are measured at carrying value which approximates fair value due to the short-term nature of these instruments. Accounts receivable and other are designated as "loans and receivables". Short-term borrowings, accounts payable and other, interest payable, long-term debt and non-recourse long-term debt are designated as "other financial liabilities".

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

Hedges

The Company uses derivatives and non-derivative financial instruments to manage changes in commodity prices, foreign currency exchange rates and interest rates. Hedge accounting is optional and it requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in commodity prices, foreign currency exchange rates and interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in

earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability ceases to be remeasured at fair value and the fair value adjustment is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

The Company uses net investment hedges to manage the carrying values of U.S. dollar and euro denominated foreign investments. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated Other Comprehensive Income or Loss (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a sale of ownership interests.

Non-Hedge Derivatives

The Company does not use derivative instruments for speculative purposes. However, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as hedging item, changes in the fair value are recorded in current period earnings.

INCOME TAXES

For non-regulated operations, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated activities of the Company recover income tax expense based on the taxes payable method when prescribed by regulators or in ratemaking agreements that are subject to regulatory approval. As a result, rates do not include the recovery of future income taxes related to temporary differences and the Company does not record future income tax assets or liabilities related to these differences. The Company expects that all unrecorded future income taxes will be recovered in rates when they become payable.

FOREIGN CURRENCY TRANSLATION

The Company's U.S. dollar operations are primarily self-sustaining. The Company also holds a self-sustaining euro equity investment in CLH. Self-sustaining operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term deposits with a term to maturity of three months or less when purchased.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of customer sales rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred for future refund or collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at the lower of cost and net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for construction, expansion, major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate regulated assets, if approved, an allowance for equity funds used during construction is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments as well as pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts which are amortized on a straight-line basis over the expected lives of the contracts.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually and written down to fair value if impairment occurs.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For certain of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

Depreciation expense for Gas Distribution and Services operations includes a provision for AROs at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation in accordance with regulatory treatment.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method and are charged to earnings as services are rendered, except for the regulated operations of Gas Distribution and Services, where contributions made to the plan are expensed as paid consistent with the recovery of such costs in rates. For defined contribution plans, contributions made by the Company are expensed.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values. Adjustments arising from plan amendments and the transitional amounts recognized on adoption of the accounting standard are amortized on a straight-line basis over the average remaining service period of the employees active at the date of amendment or transition. The excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees.

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years employees render service, except for the regulated operations of Gas Distribution and Services where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

STOCK BASED COMPENSATION

Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units vest at the completion of a 35-month term; both are settled in cash. During the term, a liability and expense are recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSU's is also dependent on the Company's current performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 *Comprehensive Income*, Section 3251 *Equity*, Section 3855 *Financial Instruments – Recognition and Measurement*, Section 3861 *Financial Instruments – Disclosure and Presentation* and Section 3865 *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in AOCI.

The adoption of the new standards did not impact the Company's earnings or cash flows.

Comprehensive Income and Equity

The new standards introduce comprehensive income, which consists of earnings and OCI. The Company's consolidated financial statements now include a Statement of Comprehensive Income. The Company's OCI is primarily comprised of the effective portion of changes in unrealized gains and losses related to cash flow hedges; the Company's share of the OCI of equity investees; and unrealized foreign exchange gains and losses related to self-sustaining foreign investments and the net investment hedges of those foreign investments.

The Company now presents a Consolidated Statement of Shareholders' Equity, which includes the change for each component of shareholders' equity. The cumulative changes in OCI are recorded in AOCI, a separate component of shareholders' equity. The cumulative translation adjustment, previously presented as a separate component of shareholders' equity, is now presented as a component of AOCI. The components of AOCI are presented in Note 17.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the carrying value of the Company's financial instruments has not changed. The methods by which the Company determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars) Increase/(Decrease)	Assets	Liabilities and Equity
Accounts Receivable and Other[1,2]	5.4	–
Deferred Amounts and Other Assets[1,2,3,4]	55.3	–
Long-Term Investments[1]	(57.3)	–
Accounts Payable and Other[2]	–	57.6
Long-Term Debt[3]	–	(52.7)
Other Long-Term Liabilities[1,2,4]	–	42.5
Future Income Taxes[1]	–	(18.9)
Non-Controlling Interests[1]	–	(26.3)
Accumulated Other Comprehensive Income[1]	–	48.2
Retained Earnings[1]	–	(47.0)
	3.4	3.4

1 *As a result of the new standards for cash flow hedges, the Company recognized unrealized net gains related to interest rate, foreign exchange and commodity hedges. The Company adjusted both deferred amounts and retained earnings for historical fair value adjustments related to certain cash flow hedges.*

2 *The Company recorded a regulatory liability due to the recognition of fixed price power contracts offset by unrealized financial instrument losses.*

3 *The Company reclassified unamortized deferred financing fees from deferred amounts and other assets to long-term debt as a result of adopting the new standards.*

4 *Relates to the recognition of gas purchase hedges for the regulated gas distribution businesses at January 1, 2007.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosures and Presentation

Effective January 1, 2008, the Company will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosures and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Company will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861 *Financial Instruments – Disclosure and Presentation.* Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand disclosure about the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

Inventories

The CICA issued Section 3031 *Inventories* effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS). This standard is not expected to materially impact the Company's financial statements.

Accounting for the Effects of Rate Regulation

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to rate regulated operations. The AcSB decided to retain much of the existing guidance related to rate-regulated operations however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465, *Income Taxes,* and the exemption from CICA Handbook Section 1100, *Generally Accepted Accounting Principles,* will be removed, effective January 1, 2009. The Company will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation where the rates approved by the regulator are designed to recover the costs of providing the products and services. The Company's significant regulated businesses and related accounting impacts are described below.

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are set based on agreements with customers and are filed with the NEB for approval. The incentive tolling settlement (ITS) is effective from January 1, 2005 to December 31, 2009 and defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval.

Athabasca Pipeline

Athabasca Pipeline is regulated by the ERCB. Tolls are established based on long-term transportation agreements with individual shippers and taxes are recorded using the taxes payable method.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline with a FERC approved tariff establishing rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls include a return on equity component of 10.75% (2006 – 10.75%) after tax.

Alliance Pipeline

The US portion of the Alliance Pipeline (Alliance) is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on Alliance entered into 15-year transportation contracts expiring in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulator. The tolls include a return on equity component of 10.88% (2006 – 10.85%) after tax for the US portion and 11.26% (2006 – 11.25%) after tax for the Canadian portion. Alliance tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. EGD's rates are set under a cost of service methodology with revenues charged to recover EGD's forecast costs and to earn a rate of return on common equity. Applications for changes to rates are made annually and are submitted for approval by the OEB.

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, interest and income taxes. The rate base is the average investment in permitted assets used in gas distribution, storage and transmission and an allowance for working capital. EGD's 2007 approved rate of return on rate base was 7.58% (2006 – 7.74%) after tax, and the approved rate of return on common equity was 8.39% (2006 – 8.74%) after tax based on a 36% (2006 – 35%) deemed common equity.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and follows a cost of service tolling methodology. An application for rate adjustments is filed annually for EUB approval. EGNB's rate of return on rate base was 9.70% (2006 – 9.78%) after tax and the approved rate of return on equity was 13.00% (2006 – 13.00%) after tax, based on equity which is capped at 50%.

REGULATORY RISK AND UNCERTAINTIES AFFECTING RECOVERY OR SETTLEMENT

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

To recognize the actions or expected actions of the regulator, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Accounting for rate-regulated entities has resulted in recording the following regulatory assets and liabilities:

(millions of dollars) December 31,	**2007**	2006	Estimated Settlement Period (years)	Earnings Impact[1] **2007**	Earnings Impact[1] 2006
Regulatory Assets/(Liabilities)					
Liquids Pipelines					
Enbridge System tolling deferrals[2]	**143.4**	166.2	1	**(22.8)**	(6.1)
Power purchase arrangements[3]	**(23.8)**	–	1-3	**(23.8)**	–
Gas Pipelines					
Deferred transportation revenue[4]	**181.4**	203.8	16-18	**5.9**	9.8
Transportation revenue adjustment[5]	**4.1**	9.3	1	**(2.6)**	(1.4)
Sponsored Investments					
Deferred transportation revenue[4]	**65.6**	47.4	18	**7.7**	7.3
Gas Distribution and Services					
EGNB regulatory deferral[6]	**117.7**	101.8	33	**10.3**	12.4
Class action lawsuit settlement[7]	**22.0**	22.0	2	**–**	13.5
Ontario hearing cost[8]	**8.1**	9.2	2	**(0.7)**	(1.7)
Purchased gas variance[9]	**(141.1)**	(127.4)	1	**(8.8)**	(99.3)
Unaccounted for gas variance[10]	**6.1**	(11.7)	1	**11.4**	(9.4)
Transactional services deferral[11]	**(8.8)**	(7.5)	1	**–**	–

1 *Represents the effect of rate regulation on after tax reported earnings.*

2 *Tolls on the Enbridge System are calculated in accordance with the ITS, System Expansion Program (SEP) II and the Terrace agreements and are established each year based on capacity, the allowed revenue requirement and the Terrace agreement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a receivable is recognized and incorporated into tolls in the subsequent year. However, recovery is dependent on volumes shipped since each shipper is only responsible for their pro-rata share of the increase in tolls. In addition, other tolling deferrals occur in accordance with the various agreements.*

3 *The power purchase arrangements liability is the fair value of fixed price contracts and related financial instruments used to manage the mix of fixed and floating power costs (see Note 18).*

4 *Deferred transportation revenue is related to the cumulative difference between GAAP depreciation expense of Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed the GAAP depreciation rates, for Alliance beginning in 2011 and ending in 2025 and for Vector beginning in 2008 and ending in 2023. This regulatory asset is not included in the rate base.*

5 *The transportation revenue adjustment is the cumulative difference between actual expenses of Alliance Pipeline US and estimated expenses included in transportation rates. The transportation revenue adjustment is recoverable under the long-term transportation agreements and is not included in the rate base.*

6 *A regulatory deferral account captures the difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance will be amortized over a recovery period approved by the EUB commencing at the end of the development period, which is currently expected to end after 2040.*

7 *Class action lawsuit settlement deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. This amount is expected to be recovered in future periods.*

8 *Ontario hearing costs are incurred by EGD for the rate hearing process. EGD has historically been granted OEB approval for recovery of such hearing costs, generally within two years.*

9 *Purchased gas variance is the difference between the actual cost and the approved cost of gas reflected in rates. EGD has historically been granted approval for recovery or required refund of this variance within the year.*

10 *Unaccounted for gas variance represents the difference between the total gas distributed by EGD and the amount of gas billed or billable to ratepayers, to the extent it is different from the approved gas variance. EGD has deferred unaccounted for gas variance and has historically been granted approval for recovery or required refund of this amount in the subsequent year.*

11 *Transactional services deferral represents the ratepayer portion of excess earnings generated from optimization of storage and pipeline capacity. EGD has historically been required to refund the amount to ratepayers in the following year.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Future Income Taxes

In the absence of rate regulation, future income tax liabilities of $517.1 million (2006 – $584.0 million) associated with certain assets, primarily property, plant and equipment, would be recorded.

The Company has recorded net future income tax liabilities of $24.0 million (2006 – $32.9 million) related to certain regulatory asset/liability deferral accounts identified above. Accumulated future income tax assets of $55.6 million (2006 – $64.7 million) related to the remaining regulatory deferral accounts have not been recognized at December 31, 2007. In the absence of rate regulation, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. As a result of these tax impacts, earnings during the year would increase by $62.2 million (2006 – $65.0 million).

Allowance For Funds Used During Construction and Other Capitalized Costs

With the pool method prescribed by regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2007, $82.2 million (2006 – $66.4 million) was included in gas mains, which are depreciated over the average service life of 25 years. In the absence of rate regulation, the majority of these costs would be charged to current earnings.

Pension Plans

Had pension costs and obligations been recognized, the net pension asset would have increased by $153.3 million at December 31, 2007 (2006 – $157.1 million) and earnings would have decreased by $1.1 million (2006 – $0.5 million).

Post-Employment Benefits Other than Pensions

In the absence of rate regulation, the cost of such benefits is accrued during the years employees render service. Had these costs been accrued, the net OPEB liability would have increased by $70.8 million (2006 – $67.1 million) and earnings would have decreased by $5.8 million (2006 – $5.5 million).

4. SEGMENTED INFORMATION

(millions of dollars) **Year ended December 31, 2007**	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	**1,090.9**	**321.3**	**270.3**	**10,227.1**	**9.8**	–	**11,919.4**
Commodity costs	–	–	–	**(9,009.5)**	–	–	**(9,009.5)**
Operating and administrative	**(426.5)**	**(87.4)**	**(79.2)**	**(535.9)**	**(14.2)**	**(20.5)**	**(1,163.7)**
Depreciation and amortization	**(155.8)**	**(83.5)**	**(74.8)**	**(277.0)**	**(0.8)**	**(5.0)**	**(596.9)**
	508.6	**150.4**	**116.3**	**404.7**	**(5.2)**	**(25.5)**	**1,149.3**
Income from equity investments	**(0.6)**	–	**96.5**	**8.8**	**64.1**	**(1.0)**	**167.8**
Other investment income	**15.5**	**23.4**	**38.8**	**28.0**	**39.1**	**50.3**	**195.1**
Interest and preferred share dividends	**(100.9)**	**(64.2)**	**(61.9)**	**(207.1)**	–	**(122.8)**	**(556.9)**
Non-controlling interest	**(1.3)**	–	**(38.4)**	**(6.2)**	–	–	**(45.9)**
Income taxes	**(134.1)**	**(39.9)**	**(54.4)**	**(44.1)**	**(2.9)**	**66.2**	**(209.2)**
Earnings applicable to common shareholders	**287.2**	**69.7**	**96.9**	**184.1**	**95.1**	**(32.8)**	**700.2**

(millions of dollars) Year ended December 31, 2006	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	1,048.1	345.9	254.7	8,981.6	14.2	–	10,644.5
Commodity costs	–	–	–	(7,824.6)	–	–	(7,824.6)
Operating and administrative	(391.2)	(96.0)	(67.7)	(485.8)	(18.2)	(25.3)	(1,084.2)
Depreciation and amortization	(153.4)	(87.5)	(71.9)	(269.1)	(0.9)	(4.6)	(587.4)
	503.5	162.4	115.1	402.1	(4.9)	(29.9)	1,148.3
Income from equity investments	(0.2)	–	111.5	17.0	52.2	(0.2)	180.3
Other investment income	3.2	9.2	2.9	17.8	45.2	29.5	107.8
Interest and preferred share dividends	(102.4)	(73.3)	(60.0)	(197.8)	–	(140.5)	(574.0)
Non-controlling interest	(1.6)	–	(48.0)	(5.1)	–	–	(54.7)
Income taxes	(128.3)	(37.1)	(34.7)	(55.8)	(9.3)	72.9	(192.3)
Earnings applicable to common shareholders	274.2	61.2	86.8	178.2	83.2	(68.2)	615.4

(millions of dollars) Year ended December 31, 2005	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	881.0	364.3	249.0	6,947.1	11.7	–	8,453.1
Commodity costs	–	–	–	(5,728.4)	–	–	(5,728.4)
Operating and administrative	(311.4)	(95.5)	(60.1)	(549.3)	(17.5)	(23.8)	(1,057.6)
Depreciation and amortization	(145.6)	(94.3)	(71.5)	(257.3)	(1.2)	(5.4)	(575.3)
	424.0	174.5	117.4	412.1	(7.0)	(29.2)	1,091.8
Income from equity investments	0.8	–	48.6	8.9	58.5	–	116.8
Other investment income	0.4	5.9	27.3	30.6	39.7	38.5	142.4
Interest and preferred share dividends	(96.5)	(81.9)	(61.8)	(178.8)	–	(127.1)	(546.1)
Non-controlling interest	(2.1)	–	(21.2)	(3.8)	(0.5)	–	(27.6)
Income taxes	(97.5)	(38.7)	(45.5)	(90.2)	(3.3)	53.9	(221.3)
Earnings applicable to common shareholders	229.1	59.8	64.8	178.8	87.4	(63.9)	556.0

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 1.

1 Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments.

TOTAL ASSETS

(millions of dollars)

December 31,	2007	2006
Liquids Pipelines	**5,334.6**	4,004.4
Gas Pipelines	**2,043.9**	2,297.0
Sponsored Investments	**2,688.1**	2,841.5
Gas Distribution and Services	**8,355.7**	7,635.4
International	**908.6**	917.2
Corporate	**576.5**	683.8
	19,907.4	18,379.3

ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)

December 31,	2007	2006	2005
Liquids Pipelines	**1,413.1**	428.8	258.6
Gas Pipelines	**200.4**	110.8	10.1
Sponsored Investments	**54.9**	33.4	15.5
Gas Distribution and Services	**609.4**	611.1	434.0
International and Corporate	**29.5**	23.4	5.9
	2,307.3	1,207.5	724.1

GEOGRAPHIC INFORMATION

Revenues[1]

(millions of dollars)

December 31,	2007	2006	2005
Canada	**8,337.0**	7,968.7	6,747.5
United States	**3,572.6**	2,661.6	1,693.9
Other	**9.8**	14.2	11.7
	11,919.4	10,644.5	8,453.1

1 *Revenues are based on the country of origin of the product or services sold.*

Property, Plant and Equipment

(millions of dollars)

December 31,	2007	2006
Canada	**10,031.2**	8,859.7
United States	**2,564.4**	2,401.8
Other	**2.0**	3.2
	12,597.6	11,264.7

5. ACQUISITIONS

On February 1, 2006, Enbridge acquired a 65% common share interest in the Olympic Pipeline Company for $112.7 million in cash. In 2005, the Company acquired interests in five other businesses for a total of $106.6 million, including $6.8 million paid in common shares of the Company.

(millions of dollars) Year ended December 31,	Olympic 2006	Combined 2005
Fair Value of Assets Acquired:		
Property, plant and equipment	107.0	66.6
Intangible assets	–	25.7
Other assets	5.0	0.7
Future income taxes	(6.1)	(16.3)
Other liabilities	(17.0)	(0.9)
	88.9	75.8
Goodwill	23.8	30.8
	112.7	106.6
Purchase Price:		
Cash (2006, net of $1.6 million cash acquired)	112.7	88.6
Contingent consideration	–	11.2
Shares issued	–	6.8
Deposit paid in 2005	(11.3)	–
	101.4	106.6

6. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) December 31, 2007	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.2%	2,688.4	1,259.9	1,428.5
Pumping Equipment, Buildings, Tanks and Other	3.7%	2,566.6	912.1	1,654.5
Land and Right-of-Way	1.8%	41.5	18.5	23.0
Under Construction	–	1,546.4	–	1,546.4
		6,842.9	2,190.5	4,652.4
Gas Pipelines				
Pipeline	3.7%	1,656.5	390.4	1,266.1
Land and Right-of-Way	2.7%	38.8	7.6	31.2
Metering and Other	4.6%	101.6	16.0	85.6
Under Construction	–	272.6	–	272.6
		2,069.5	414.0	1,655.5
Sponsored Investments				
Pipeline	4.2%	1,402.8	284.1	1,118.7
Other	7.6%	108.7	13.9	94.8
		1,511.5	298.0	1,213.5
Gas Distribution and Services				
Gas Mains	3.3%	2,748.9	708.7	2,040.2
Gas Services	3.6%	2,224.0	676.4	1,547.6
Regulating and Metering Equipment	3.7%	581.9	158.0	423.9
Storage	2.7%	246.4	61.0	185.4
Computer Technology	19.4%	185.2	81.6	103.6
Other	4.6%	310.6	106.5	204.1
Under Construction	–	495.7	–	495.7
		6,792.7	1,792.2	5,000.5
International and Corporate – Other	8.1%	113.0	37.3	75.7
		17,329.6	4,732.0	12,597.6

(millions of dollars) December 31, 2006	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.3%	2,781.6	1,241.3	1,540.3
Pumping Equipment, Buildings, Tanks and Other	3.7%	2,501.3	874.1	1,627.2
Land and Right-of-Way	1.7%	40.1	18.4	21.7
Under Construction	–	304.8	–	304.8
		5,627.8	2,133.8	3,494.0
Gas Pipelines				
Pipeline	3.7%	1,999.7	397.0	1,602.7
Land and Right-of-Way	2.7%	46.3	8.0	38.3
Metering and Other	4.5%	128.0	20.1	107.9
Under Construction	–	64.2	–	64.2
		2,238.2	425.1	1,813.1
Sponsored Investments				
Pipeline	4.4%	1,372.8	219.2	1,153.6
Other	5.2%	83.8	9.6	74.2
		1,456.6	228.8	1,227.8
Gas Distribution and Services				
Gas Mains	4.2%	2,342.2	531.3	1,810.9
Gas Services	4.5%	1,933.6	523.6	1,410.0
Regulating and Metering Equipment	3.9%	624.5	153.9	470.6
Storage	2.7%	270.3	60.2	210.1
Computer Technology	18.1%	346.6	195.3	151.3
Other	2.6%	426.5	112.1	314.4
Under Construction	–	308.7	–	308.7
		6,252.4	1,576.4	4,676.0
International and Corporate – Other	7.0%	86.3	32.5	53.8
		15,661.3	4,396.6	11,264.7

7. JOINT VENTURES

Enbridge has joint venture interests in the following entities:

December 31, *(millions of dollars)*	Ownership Interest	2007 Net Assets	2006 Net Assets
Liquids Pipelines			
Olympic Pipeline	65%	**97.8**	111.1
Other	30% - 50%	**54.8**	58.5
Gas Pipelines			
Alliance Pipeline US	50%	**364.3**	422.7
Vector Pipeline	60%	**408.4**	442.3
Enbridge Offshore Pipelines – various joint ventures	22% - 75%	**441.3**	517.4
Sponsored Investments			
Alliance Pipeline Canada	50%	**354.8**	357.7
Other	33% - 50%	**69.2**	56.4
Gas Distribution and Services			
Aux Sable	42.7%	**150.6**	178.7
Other	42.7% - 70%	**49.7**	55.3
		1,990.9	2,200.1

The following summarizes the impact of proportionately consolidating the joint ventures on the consolidated financial statements of Enbridge:

(millions of dollars) Year ended December 31,	2007	2006	2005
Earnings			
Revenues	**844.5**	939.4	1,402.5
Commodity costs	**(132.9)**	(184.8)	(608.2)
Operating and administrative	**(207.6)**	(257.2)	(320.7)
Depreciation and amortization	**(152.9)**	(164.8)	(162.3)
Interest expense	**(106.4)**	(110.8)	(117.1)
Other investment income	**6.6**	7.3	4.6
Proportionate share of earnings	**251.3**	229.1	198.8
Cash Flows			
Cash provided by operations	**312.0**	318.3	271.1
Cash used in investing activities	**(131.9)**	(59.5)	(13.4)
Cash used in financing activities	**(183.9)**	(258.9)	(268.0)
Proportionate share of decrease in cash and cash equivalents	**(3.8)**	(0.1)	(10.3)

(millions of dollars) December 31,	2007	2006
Financial Position		
Current assets	**146.0**	178.7
Property, plant and equipment, net	**2,913.1**	3,224.6
Deferred amounts and other assets	**277.6**	288.5
Current liabilities	**(139.8)**	(151.8)
Long-term debt	**(1,181.6)**	(1,315.4)
Other long-term liabilities	**(24.4)**	(24.5)
Proportionate share of net assets	**1,990.9**	2,200.1

8. LONG-TERM INVESTMENTS

(millions of dollars) December 31,	Ownership Interest	**2007**	2006
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	22.8%	**17.2**	21.5
Sponsored Investments			
The Partnership	15.1%	**944.8**	1,105.5
Gas Distribution and Services			
Noverco Common Shares	32.1%	**11.6**	37.0
Other		**1.5**	1.4
International			
Compañía Logística de Hidrocarburos CLH, S.A.	25.0%	**626.4**	662.2
Corporate		**16.1**	17.1
Other Investments			
Gas Distribution and Services			
Noverco Preferred Shares		**181.4**	181.4
Fuel Cell Energy		**25.0**	25.0
International			
Oleoducto Central S.A.		**223.3**	223.3
Corporate			
Value Creation		**29.0**	25.0
		2,076.3	2,299.4

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $581.1 million at December 31, 2007 (2006 – $617.5 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values and is amortized over the economic life of the assets. Consolidated retained earnings at December 31, 2007 includes undistributed earnings from equity investments of $5.0 million (2006 – $10.4 million).

THE PARTNERSHIP

The Company has a combined 15.1% ownership in EEP, through a 2.0% general partner interest, a 4.2% interest in Class B units, a 6.4% interest in Class C units and a 2.5% interest in EEP via a 17.2% investment in EEM, which owns 14.6% of EEP via its 100% interest in EEP's i-units. The Company recorded investment income from EEP of $130.4 million (2006 – $111.5 million) including dilution gains.

Although 82.8% of EEM is widely held, the Company has voting control and; therefore, consolidates EEM, including its investment in EEP of $456.4 million (2006 – $545.0 million). Net of non-controlling interest in EEM, the book value of the Company's investment in EEP is $566.7 million (2006 – $654.3 million.)

In the second quarter of 2007, EEP issued Class A and Class C partnership units. As Enbridge did not fully participate in these offerings, dilution gains net of tax and non-controlling interest of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%.

In 2006, the Company acquired 5.4 million Class C units of EEP for $280.2 million. The Class C units have the same voting rights as Class A and B units and are entitled to quarterly distributions equal to those paid to Class A and B unitholders. Prior to August 15, 2009, distributions are paid in additional Class C units, where Class C units are valued at the market value of Class A units. After August 15, 2009, distributions will be paid in cash and, subject to the approval of existing Class A and Class B unitholders, Class C units will convert into Class A units on a one-to-one basis. If approval of the conversion is not received, the Class C units will receive cash distributions equal to 115% of those paid to Class A unitholders.

NOVERCO

The Company owns a preferred share investment in Noverco of $181.4 million (2006 – $181.4 million), which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%. The fair value of the investment approximates its carrying value as its return is based on a floating rate.

The Company also owns an equity investment in the common shares of Noverco of $11.6 million (2006 – $37.0 million). Noverco owns an approximate 9.5% (2006 – 9.5%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.1% (2006 – 3.2%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $154.3 million (2006 – $135.7 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from the earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2007, the Company recorded equity investment earnings of $8.5 million (2006 – $16.8 million) related to its interest in Noverco.

In 2005, the Company reclassified $51.2 million in dividends paid to Noverco representing the reciprocal portion of dividends paid to Noverco from September 1, 1997 to December 31, 2004. The reclassification increased equity investments and retained earnings by $51.2 million.

CLH

The Company owns a 25% equity interest in CLH of $626.4 million (2006 – $662.2 million), a refined products transportation and storage company in Spain. In 2007, the Company recorded equity investment income from CLH of $64.1 million (2006 – $52.3 million).

OCENSA

The Company owns an investment in OCENSA, a crude oil export pipeline in Colombia of $223.3 million (US$160.2 million) (2006 – $223.3 million; US$160.2 million), which earns a fixed rate of return. The fair value of this investment is approximately $198.0 million (US$200.4 million) (2006 – $245.9 million; US$211.0 million), estimated using year-end market information.

9. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars) December 31,	**2007**	2006
Regulatory deferrals	**428.2**	395.9
Contractual receivables	**152.0**	142.8
Long-term portion of derivative financial instruments	**329.0**	205.1
Pension asset	**72.3**	56.0
Deferred financing charges *(Note 2)*	**–**	52.7
Affiliate long-term note receivable (US$130.0 million) *(Note 23)*	**128.5**	–
Other	**72.0**	72.0
	1,182.0	924.5

At December 31, 2007, deferred amounts of $42.3 million (2006 – $146.8 million) were subject to amortization and are presented net of accumulated amortization of $23.2 million (2006 – $67.6 million). Amortization expense in 2007 was $3.6 million (2006 – $10.1 million; 2005 – $12.5 million).

10. INTANGIBLE ASSETS

(millions of dollars) **December 31, 2007**	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Transportation agreements	**4.2%**	**241.8**	**36.3**	**205.5**
Customer lists	**7.1%**	**8.3**	**1.8**	**6.5**
		250.1	**38.1**	**212.0**

(millions of dollars) December 31, 2006	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Transportation agreements	4.2%	261.5	28.4	233.1
Customer lists	7.1%	9.8	1.4	8.4
		271.3	29.8	241.5

Amortization expense of $10.4 million was recorded for the year ended December 31, 2007 (2006 – $11.0 million; 2005 – $11.1 million).

11. GOODWILL

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	Consolidated
Balance at January 1, 2006	–	29.9	308.1	29.2	367.2
Olympic Pipeline acquisition	23.8	–	–	–	23.8
Foreign exchange and other	0.7	–	–	3.2	3.9
Balance at December 31, 2006	**24.5**	**29.9**	**308.1**	**32.4**	**394.9**
Foreign exchange and other	**(6.2)**	**(4.6)**	**–**	**3.9**	**(6.9)**
Balance at December 31, 2007	**18.3**	**25.3**	**308.1**	**36.3**	**388.0**

12. DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	**2007**	2006
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	200.0
Medium-term notes	5.62%	2009 - 2036	**824.6**	824.6
Other (US$365.0 million; 2006 – nil)[1]			**516.5**	131.0
Gas Distribution and Services				
Debentures	11.06%	2009 - 2024	**485.0**	585.0
Medium-term notes	5.69%	2008 - 2036	**1,865.0**	1,665.0
Other			**9.4**	8.2
Corporate				
U.S.dollar term notes (US$1,354.3 million; 2006 – US$417.0 million)	5.69%	2014 - 2022	**1,341.2**	485.9
Medium-term notes	5.72%	2008 - 2035	**1,900.0**	2,094.9
Preferred securities			**–**	200.0
Other (US$317.0 million; 2006 – US$348.4 million)[2]			**1,252.2**	1,396.4
Deferred debt issue costs *(Note 2)*			**(59.7)**	–
Total Debt			**8,334.2**	7,591.0
Current Maturities			**(605.2)**	(537.0)
Long-Term Debt			**7,729.0**	7,054.0

1 *Primarily credit facility draws.*
2 *Primarily commercial paper borrowings.*

Short-term debt of $1,764.8 million (2006 – $1,519.1 million) is supported by the availability of long-term committed credit facilities and has been classified as long-term debt.

Long-term debt maturities for the years ending December 31, 2008 through 2012 are $605.2 million, $455.0 million, $600.9 million, $151.1 million and $251.1 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates.

On February 15, 2007, the Company redeemed $200.0 million of 7.8% Preferred Securities for $25.00 per security plus accrued and unpaid interest.

FAIR VALUE OF DEBT

December 31,	**2007**		2006	
(millions of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**1,541.1**	**1,642.5**	1,155.6	1,301.6
Gas Distribution and Services	**2,359.4**	**2,571.0**	2,258.2	2,613.8
Corporate	**4,493.4**	**4,640.7**	4,177.2	4,294.0

The fair value of debt does not include the effects of hedging.

INTEREST EXPENSE

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Long-term debt	**439.5**	403.4	382.8
Non-recourse long-term debt	**102.0**	104.9	112.1
Commercial paper and other short-term debt	**54.5**	60.3	40.6
Short-term borrowings	**15.2**	19.1	12.7
Capitalized	**(61.2)**	(20.6)	(9.0)
	550.0	567.1	539.2

In 2007, total interest paid was $607.3 million (2006 – $563.3 million; 2005 – $537.1 million).

INTEREST RATE MANAGEMENT

The impact on effective interest rates of derivative instruments used to manage interest rate risk and the debt related to these instruments are as follows:

(millions of dollars) **December 31, 2007**	Maturity	Effective Interest Rate[1]	Notional Amounts
Liquids Pipelines			
Floating to fixed interest swap (commercial paper)	2029	6.0%	25.4
Corporate			
Floating to fixed interest swap (commercial paper)	2008 - 2009	4.5%	750.0
Floating to fixed interest swap (commercial paper)	2008 - 2009	4.3%	US$186.6

1 *After giving effect to the derivative financial instruments.*

CREDIT FACILITIES

(millions of dollars) **December 31, 2007**	Expiry Dates	Total Facility	Available	Drawdowns
Liquids Pipelines	2008 - 2009	794.1	433.4	360.7
Gas Distribution and Services	2008 - 2009	1,006.9	1,000.0	6.9
Corporate	2009 - 2012	3,842.9	3,842.9	–
		5,643.9	5,276.3	367.6

Credit facilities carry a weighted average standby fee of 0.062% per annum on the unused portion and drawdowns bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2009 to 2012.

13. NON-RECOURSE DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	**2007**	2006
Gas Pipelines				
Long-term credit facilities (US$1.9 million; 2006 – US$6.0 million)	5.26%	2012	**1.9**	6.9
Senior notes (US$441.8 million; 2006 – US$469.5 million)	6.74%	2015 - 2025	**436.5**	547.1
Capital lease obligations	11.24%	2013 - 2020	**39.9**	49.6
Sponsored Investments				
Credit facilities	5.12%	2010 - 2012	**141.5**	94.4
Medium-term notes	4.69%	2009 - 2014	**190.0**	190.0
Senior notes	6.85%	2015 - 2025	**707.7**	733.7
Fair value increment on senior notes acquired			**43.3**	48.2
Gas Distribution and Services				
Term debt (US$15.7 million; 2006 – US$5.8 million)	6.3%	2008 - 2010	**15.5**	6.8
Capital lease obligations	12.0%	2016 - 2021	**4.9**	5.4
Deferred debt issue costs *(Note 2)*			**(11.7)**	–
Total Non-Recourse Debt			**1,569.5**	1,682.1
Current Maturities			**(61.1)**	(60.1)
Non-Recourse Long-Term Debt			**1,508.4**	1,622.0

Long-term debt maturities on non-recourse borrowings for the years ending December 31, 2008 through 2012 are $61.1 million, $168.3 million, $176.8 million, $68.6 million and $118.4 million, respectively. The medium-term notes and senior notes bear interest at fixed rates.

Certain assets of Alliance Pipeline Canada are pledged as collateral to Alliance Pipeline Canada's lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US are pledged as collateral to Alliance Pipeline US's lenders and to the lenders to Alliance Pipeline Canada.

Not including the effects of hedging, non-recourse debt has a fair value of $1,634.8 million (2006 – $1,786.6 million).

14. NON-CONTROLLING INTERESTS

(millions of dollars) December 31,	**2007**	2006
EEM	**335.1**	398.5
EGD Preferred Shares	**100.0**	100.0
EIF	**155.9**	167.3
EGNB	**48.8**	39.8
Other	**10.7**	9.6
	650.5	715.2

Non-controlling interest in EEM represents the 82.8% of the listed shares of EEM not held by the Company.

The Company owns 100% of the common shares of EGD; however, the 4,000,000 4.82% Cumulative Redeemable EGD Preferred Shares held by a third party are entitled to a claim on the assets of EGD prior to the common shareholder. Subsequent to July 1, 2009, EGD may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 plus all accrued and unpaid dividends to the redemption date. The preferred shares have no fixed maturity date.

Non-controlling interest in EIF represents 58.1% of voting units which are held by public unitholders. Non-controlling interest in EGNB represents 29.2% held by third parties.

15. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares.

COMMON SHARES

December 31,	**2007**		2006		2005	
(millions of dollars; number of common shares in millions)	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**351.8**	**2,416.1**	348.9	2,343.8	346.2	2,282.4
Common shares issued	**15.0**	**566.4**	–	–	–	–
Exercise of stock options	**1.2**	**26.3**	2.4	53.9	2.1	40.0
Dividend Reinvestment and Share Purchase Plan	**0.5**	**17.7**	0.5	18.4	0.4	14.6
Issued for business acquisition	**–**	**–**	–	–	0.2	6.8
Balance at end of year	**368.5**	**3,026.5**	351.8	2,416.1	348.9	2,343.8

PREFERRED SHARES

The 5.0 million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 per share plus all accrued and unpaid dividends.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 11.1 million shares (2006 – 10.6 million shares), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes that any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

(number of common shares in millions)

December 31,	**2007**	2006	2005
Weighted average shares outstanding	**355.3**	340.0	337.4
Effect of dilutive options	**3.0**	3.3	3.8
Diluted weighted average shares outstanding	**358.3**	343.3	341.2

For the year ended December 31, 2007, 1,158,200 anti-dilutive stock options (2006 – 1,548,900; 2005 – nil) with a weighted average exercise price of $38.26 (2006 – $36.47) were excluded from the diluted earnings per share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

16. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four plans for mid to long-term incentive compensation: the Incentive Stock Option (ISO) Plan, Performance Based Stock Option (PBSO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 14.7 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2007 for ISOs is $9.0 million (2006 – $10.5 million; 2005 – $5.5 million).

Outstanding Incentive Stock Options

December 31,	**2007**		2006		2005	
(options in thousands; exercise price in dollars)	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**9,186**	**24.97**	9,434	22.09	9,650	19.86
Options granted	**1,158**	**38.26**	1,595	36.41	1,533	31.70
Options exercised	**(1,046)**	**19.21**	(1,698)	19.38	(1,617)	17.51
Options cancelled or expired	**(61)**	**32.97**	(145)	28.81	(132)	26.39
Options at end of year	**9,237**	**27.24**	9,186	24.97	9,434	22.09
Options vested	**5,865**	**22.87**	5,323	20.54	5,248	18.74

The total intrinsic value of ISOs exercised during the year ended December 31, 2007 was $19.1 million (2006 – $27.8 million; 2005 – $21.3 million) and cash received on exercise was $20.1 million (2006 – $32.9 million; 2005 – $28.3 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2007 was $94.2 million and $85.5 million, respectively.

Incentive Stock Option Characteristics

(options in thousands; exercise price in dollars)	Options Outstanding			Options Vested	
December 31, 2007 Exercise Price	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
10.00 - 14.99	**441**	**2.2**	**13.28**	**441**	**13.28**
15.00 - 19.99	**1,276**	**2.4**	**18.29**	**1,276**	**18.29**
20.00 - 24.99	**2,160**	**4.6**	**21.28**	**2,160**	**21.28**
25.00 - 29.99	**1,365**	**6.0**	**25.74**	**972**	**25.74**
30.00 - 34.99	**1,370**	**7.1**	**31.79**	**648**	**31.73**
35.00 - 38.26	**2,625**	**8.5**	**37.25**	**368**	**36.47**
	9,237	**5.9**	**27.24**	**5,865**	**22.87**

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2007**	2006	2005
Fair value per option (dollars)	**6.16**	6.30	5.31
Valuation assumptions[1]			
Expected option term (years)	**6**	8	8
Expected volatility	**18.10%**	19.00%	16.00%
Expected dividend yield	**3.22%**	3.23%	3.17%
Risk-free interest rate	**4.11%**	4.16%	4.40%

1 *The expected option term and the expected volatility are based on historical information.*

As of December 31, 2007, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $8.5 million. The cost is expected to be recognized over a period of 2.3 years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 and August 15, 2007. All performance targets and time vesting requirements for the 2002 PBSO grant have been met. The 2002 PBSO grant will expire on September 16, 2010. The 2007 PBSO grant performance targets are based on the Company's share price. Time vesting requirements for the 2007 PBSO grant are fulfilled evenly over a five-year term, ending August 15, 2012. Under the 2007 PBSO plan performance vesting targets must be met by February 15, 2014 otherwise the options expire. If targets are met by February 15, 2014, the options are exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2007 for PBSOs was $0.7 million.

Outstanding Performance Based Stock Options

December 31,	2007		2006		2005	
(options in thousands; exercise price in dollars)	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**1,379**	**23.15**	2,105	21.57	2,555	20.68
Options granted	**2,345**	**36.57**	–	–	–	–
Options exercised	**(136)**	**23.15**	(645)	18.00	(450)	16.51
Options cancelled	**–**	**–**	(81)	23.15	–	–
Options at end of year	**3,588**	**31.92**	1,379	23.15	2,105	21.57
Options vested	**1,243**	**23.15**	1,119	23.15	1,457	20.87

The total intrinsic value of PBSOs exercised during the year ended December 31, 2007 was $1.9 million (2006 – $11.4 million; 2005 – $7.8 million) and cash received on exercise was $3.1 million (2006 – $11.6 million; 2005 – $7.4 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2007 is $19.8 million and $17.8 million, respectively.

Performance Based Stock Option Characteristics

(options in thousands; exercise price in dollars)	Options Outstanding			Options Vested	
December 31, 2007 Exercise Price	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
23.15	**1,243**	**2.7**	**23.15**	**1,243**	**23.15**
36.57	**2,345**	**7.6**	**36.57**	**–**	**–**
	3,588	**5.9**	**31.92**	**1,243**	**23.15**

Assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2007**
Fair value per option (dollars)	**3.40**
Valuation assumptions[1]	
Expected option term (years)	**8**
Expected volatility	**13.60%**
Expected dividend yield	**3.57%**
Risk-free interest rate	**4.38%**

1 *The expected option term and the expected volatility are based on historical information.*

As of December 31, 2007, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $7.3 million. The cost is expected to be recognized over a period of 4.6 years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's current share price and by a performance multiplier. The performance multiplier ranges from 0, if the Company's performance fails to meet threshold performance levels, to a maximum of 2, if the Company performs within the highest range of its performance targets. The performance multiplier for the 2005 and 2006 grants is based on the Company's total shareholder return over the three-year performance period relative to a specified peer group of

companies. The 2007 grant derives the performance multiplier through a calculation of the Company's Price/Earnings ratio relative to a specified peer group of companies and the Company's growth in earnings per share relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2007 for PSUs was $3.0 million (2006 – $4.1 million; 2005 – $2.5 million). An estimated performance multiplier of 0.73, 1.0 and 1.0 was used to calculate the expense based upon historical performance for the 2005, 2006 and 2007 grants, respectively.

Outstanding Performance Stock Units

December 31,	**2007**	2006	2005
Units at beginning of year	**328,716**	200,652	67,688
Units granted	**137,200**	117,900	130,130
Units cancelled	**(2,384)**	–	(3,265)
Units matured	**(209,827)**	–	–
Dividend reinvestment	**13,911**	10,164	6,099
Units at end of year	**267,616**	328,716	200,652

Of the PSUs outstanding at December 31, 2007, 125,777 units have a performance period ending December 31, 2008 and 141,839 units have a performance period ending December 31, 2009. The total intrinsic value of PSUs outstanding at December 31, 2007 is $10.7 million.

RESTRICTED STOCK UNITS

Enbridge has a RSU plan where cash awards are granted to certain non-executive employees of the Company. After the thirty-five month maturity period, RSU holders receive cash equal to the Company's current share price for each RSU held. Compensation expense recorded for the year ended December 31, 2007 for RSUs was $7.1 million (2006 – $0.8 million; 2005 – nil).

Outstanding Restricted Stock Units

December 31,	**2007**	2006
Units at beginning of year	**183,253**	–
Units granted	**276,875**	181,882
Units cancelled	**(18,627)**	–
Dividend reinvestment	**15,120**	1,371
Units at end of year	**456,621**	183,253

The total intrinsic value of RSUs outstanding at December 31, 2007 is $18.3 million.

As of December 31, 2007, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $15.5 million, expected to be recognized over a period of 1.7 years.

17. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

(millions of dollars)	Cash Flow Hedges	Equity Investees	Non-Controlling Interests	Cumulative Translation Adjustment	Net Investment Hedges	Total
Balance at January 1, 2006	–	–	–	(486.7)	428.1	(58.6)
Tax impact	–	–	–	–	(113.2)	(113.2)
	–	–	–	(486.7)	314.9	(171.8)
Changes during the period	–	–	–	87.6	(49.0)	38.6
Tax impact	–	–	–	–	(2.6)	(2.6)
	–	–	–	87.6	(51.6)	36.0
Balance at December 31, 2006	–	–	–	(399.1)	263.3	(135.8)
Adjustment on adoption *(Note 2)*	**79.4**	**(57.3)**	**26.3**	**–**	**–**	**48.4**
Tax impact	**(20.3)**	**20.1**	**–**	**–**	**–**	**(0.2)**
	59.1	**(37.2)**	**26.3**	**–**	**–**	**48.2**
Changes during the period	**94.8**	**(29.2)**	**4.9**	**(447.1)**	**193.9**	**(182.7)**
Tax impact	**(5.1)**	**9.4**	**–**	**–**	**(19.0)**	**(14.7)**
	89.7	**(19.8)**	**4.9**	**(447.1)**	**174.9**	**(197.4)**
Balance at December 31, 2007	**148.8**	**(57.0)**	**31.2**	**(846.2)**	**438.2**	**(285.0)**

18. FINANCIAL INSTRUMENTS & RISK MANAGEMENT

DERIVATIVE FINANCIAL INSTRUMENTS USED FOR RISK MANAGEMENT

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively, market price risk). The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed, and the risk management instruments to mitigate them.

Foreign Exchange

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and euro denominated investments, where both carrying values and earnings are subject to foreign exchange rate variability. The Company uses long dated par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure related to both changes in carrying values of its equity investments and cash flows from other investments. In addition, the Company also uses short term foreign exchange forward contracts to manage exposure related to foreign currency denominated receivables and payables.

Interest Rate Risk

The Company is exposed to interest rate fluctuations on the cost of variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company is also exposed to fluctuations in interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into treasury locks or forward starting interest rate swaps to hedge a portion of the interest cost of these future debt issues.

Commodity Price Risk

The Company may use natural gas price swaps, futures and options to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector pipelines. The Company may also uses natural gas, power, crude oil and natural gas liquids swaps or options to fix the value of variable price exposures that arise from other commodity usage, storage, transportation and supply agreements.

The Company's regulated Liquids Pipelines segment uses a fixed price contract and related financial instrument to manage the mix of fixed and floating power costs. The Company recognizes the fair value of the fixed price contract, the fair value of the financial instrument and a regulatory liability that will be recognized over the life of the fixed price contract. At December 31, 2007, the Company recognized a liability of $3.5 million for unrealized financial instrument losses, an asset of $27.3 million related to the fixed price power contract and a regulatory liability of $23.8 million.

FAIR VALUE OF FINANCIAL INSTRUMENTS USED FOR RISK MANAGEMENT

Derivatives

The fair values of derivatives have been estimated using year-end market information. These fair values approximate the amount the Company would receive or pay to terminate the contracts. The current portion of derivatives is included in Accounts Receivable and Other and Accounts Payable and Other, while the long-term portion is included in Deferred Amounts and Other Assets and Other Long-Term Liabilities.

December 31,	**2007**			2006		
(millions of dollars unless otherwise noted)	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**138.0**	**46.7**	**2013 - 2022**	307.3	(0.5)	2007 - 2022
Euro cross currency swaps	**447.6**	**27.4**	**2008 - 2019**	447.6	(9.9)	2007 - 2019
Forwards (cumulative exchange amounts)	**2,608.0**	**226.3**	**2008 - 2022**	1,536.7	231.3	2007 - 2022
Interest rates						
Interest rate swaps/collars	**1,117.0**	**(8.6)**	**2008 - 2029**	1,947.3	(17.2)	2007 - 2029
Energy commodities						
Energy commodity (bcf)	**452.9**	**(43.5)**	**2008 - 2010**	100.1	(12.9)	2007 - 2011
Natural gas supply (bcf)	**0.7**	**(1.1)**	**2008**	29.1	(26.6)	2007
Power (MW/H)	**57.0**	**20.6**	**2008 - 2024**	25.8	(8.3)	2007 - 2024

Derivative Instruments used as Cash Flow Hedges

(millions of dollars unless otherwise noted) **December 31, 2007**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange			
U.S. cross currency swaps	**138.0**	**46.7**	**2013 - 2022**
Forwards (cumulative exchange amounts)	**1,761.4**	**138.1**	**2008 - 2022**
Interest rates			
Interest rate swaps/collars	**1,117.0**	**(8.6)**	**2008 - 2029**
Energy commodities			
Energy commodity (bcf)	**43.6**	**3.2**	**2008 - 2010**
Natural gas supply (bcf)	**0.5**	**(1.0)**	**2008**
Power (MW/H, net)	**2.0**	**(2.1)**	**2008 - 2017**

The Company estimates that $1.3 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months.

Derivative and Other Financial Instruments used as Net Investment Hedges

(millions of dollars unless otherwise noted) **December 31, 2007**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange			
Euro cross currency swaps	**447.6**	**27.4**	**2008 - 2019**
Forwards (cumulative exchange amounts)	**749.9**	**187.0**	**2013 - 2020**

The Company has also designated a US$300 million medium-term note and US$317 million of commercial paper as hedges of certain US dollar investments.

Fair Value Hedges

As at December 31, 2007, the Company did not have any outstanding fair value hedges.

Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The fair value of other financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates.

Unrealized Gains and Losses on Non-Hedging Derivatives

The Company does not use derivative instruments for speculative purposes; however, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as a hedging item, changes in the fair value are recorded in current period earnings. The Company had an unrealized loss of $32.3 million (after tax) for the year ended December 31, 2007 on certain non-qualifying derivative instruments related to fixed price commodity purchases and sales.

CREDIT RISK

Entering into derivative financial instruments can give rise to credit risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company enters into risk management transactions only with institutions that possess high investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. The Company has no significant concentration with any single counterparty. The Company has credit risk of $267.8 million (2006 – $267.3 million; 2005 – $352.4 million) related to its derivative counterparties.

Credit risk also arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process.

19. INCOME TAXES

INCOME TAX RATE RECONCILIATION

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Earnings before income taxes	**916.3**	814.6	784.2
Combined statutory income tax rate	**33.9%**	34.4%	35.2%
Income taxes at statutory rate	**310.6**	280.2	276.0
Increase/(decrease) resulting from:			
Legislated tax changes	**(62.8)**	(63.0)	1.2
Future income taxes related to regulated operations	**(5.8)**	(10.5)	(15.3)
Non-taxable items, net	**(18.5)**	(21.4)	(44.1)
Lower foreign tax rates	**(6.4)**	(6.7)	(9.6)
Large Corporations Tax in excess of surtax	**–**	–	15.1
Other	**(7.9)**	13.7	(2.0)
Income Taxes	**209.2**	192.3	221.3
Effective income tax rate	**22.8%**	23.6%	28.2%

In 2007, income taxes paid amounted to $226.2 million (2006 – $182.6 million; 2005 – $150.3 million).

COMPONENTS OF FUTURE INCOME TAXES

(millions of dollars)

December 31,	**2007**	2006
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	**608.6**	639.8
Differences in accounting and tax bases of investments	**337.0**	375.6
Other comprehensive income	**42.4**	–
Other	**101.8**	201.7
	1,089.8	1,217.1
Future Income Tax Assets		
Loss carryforwards	**222.0**	257.9
Other	**78.9**	96.8
	300.9	354.7
Total Net Future Income Tax Liability	**788.9**	862.4

Net future income tax liability of $788.9 million (2006 – $862.4 million) includes future income tax liabilities of $975.6 million (2006 – $1,062.5) net of future tax assets of $186.7 million (2006 – $200.1 million).

At December 31, 2007, the Company has recognized the benefit of unused tax loss carryforwards of $665.1 million (2006 – $760.6 million). Unused tax loss carryforwards expire as follows: 2009 – $0.4 million; 2014 – $2.6 million; 2015 – $6.3 million and 2019 and beyond – $655.8 million.

GEOGRAPHIC COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

(millions of dollars) December 31,	**2007**	2006	2005
Earnings before income taxes			
Canada	**511.1**	430.7	487.3
United States	**210.2**	237.8	150.5
Other	**195.0**	146.1	146.4
	916.3	814.6	784.2
Current income taxes			
Canada	**152.7**	204.3	106.9
United States	**11.9**	0.1	–
Other	**3.8**	8.9	6.3
	168.4	213.3	113.2
Future income taxes			
Canada	**(36.3)**	(112.0)	49.4
United States	**77.1**	91.0	58.7
	40.8	(21.0)	108.1
Current and future income taxes	**209.2**	192.3	221.3

20. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits, or both to employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides Company funded defined benefit pension benefits for U.S. based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2007.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	December 31, 2006	December 31, 2009
Enbridge U.S.	December 31, 2006	December 31, 2007
Gas Distribution and Services	December 31, 2006	December 31, 2009

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, pension costs equal amounts required to be contributed by the Company. Pension costs in respect of these plans during the year were $3.6 million (2006 – $3.0 million; 2005 – $2.4 million).

POST-EMPLOYMENT BENEFITS OTHER THAN PENSIONS

Post-employment benefits other than pensions primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	OPEB		Pension Benefits	
(millions of dollars)	**2007**	2006	**2007**	2006
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**193.2**	191.6	**1,109.0**	1,039.3
Service cost	**4.7**	5.2	**43.8**	37.5
Interest cost	**10.1**	10.0	**57.9**	54.2
Amendments	**–**	–	**0.1**	2.9
Employee's contributions	**0.4**	0.4	**–**	–
Actuarial loss/(gain)	**(10.2)**	(7.7)	**(46.4)**	17.3
Benefits paid	**(6.7)**	(6.2)	**(42.2)**	(42.5)
Effect of exchange rate changes	**(8.1)**	(0.1)	**(21.8)**	0.3
Benefit obligation at end of year	**183.4**	193.2	**1,100.4**	1,109.0
Change in plan assets				
Fair value of plan assets at beginning of year	**50.2**	43.3	**1,227.1**	1,191.1
Actual return on plan assets	**1.7**	1.5	**104.8**	78.8
Employer's contributions	**8.1**	11.0	**44.1**	0.7
Employee's contributions	**0.4**	0.4	**–**	–
Benefits paid	**(6.7)**	(6.2)	**(42.2)**	(42.5)
Other	**–**	–	**(1.5)**	(1.1)
Effect of exchange rate changes	**(5.9)**	0.2	**(22.4)**	0.1
Fair value of plan assets at end of year	**47.8**	50.2	**1,309.9**	1,227.1
Funded Status				
Benefit obligation	**(183.4)**	(193.2)	**(1,100.4)**	(1,109.0)
Fair value of plan assets	**47.8**	50.2	**1,309.9**	1,227.1
Overfunded/(Underfunded) status at end of year	**(135.6)**	(143.0)	**209.5**	118.1
Contribution after measurement date	**1.0**	0.4	**–**	16.7
Unamortized prior service cost	**–**	–	**12.8**	15.5
Unamortized transitional obligation/(asset)	**12.1**	13.4	**(17.6)**	(19.8)
Unamortized net loss	**32.9**	46.0	**13.5**	93.1
Net amount recognized at end of year	**(89.6)**	(83.2)	**218.2**	223.6

The amounts recognized include all of the Company's plans; however, the Gas Distribution and Services plans are funded through regulated rates on a cash basis and are not recorded as net pension assets or liabilities. Excluding Gas

Distribution and Services plans, the Company's plans using the accrual method provide for a net pension asset of $64.9 million (2006 – $66.4 million) and a net OPEB liability of $18.8 million (2006 – $17.0 million). The pension asset is recorded on the balance sheet in Deferred Amounts and Other Assets while the pension liability is recorded in Other Long-Term Liabilities, with the current portion for each recorded in working capital accounts.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2007**	2006	2005	**2007**	2006	2005
Discount rate	**5.71%**	5.37%	5.30%	**5.65%**	5.27%	5.24%
Average rate of salary increases				**5.00%**	5.00%	4.44%

NET PENSION PLAN AND OPEB COSTS RECOGNIZED

(millions of dollars)

Year ended December 31,	2007	2006	2005
Benefits earned during the year	**52.1**	45.7	32.3
Interest cost on projected benefit obligations	**68.0**	64.2	63.2
Actual return on plan assets	**(106.5)**	(80.3)	(162.9)
Difference between actual and expected return on plan assets	**19.9**	(3.4)	87.3
Amortization of prior service costs	**2.0**	2.0	2.3
Amortization of transitional obligation	**(0.9)**	(0.8)	0.2
Amortization of actuarial loss	**13.9**	15.3	9.6
Amount charged to EEP	**(11.3)**	(10.5)	(10.2)
Pension and OPEB cost recognized	**37.2**	32.2	21.8

The table reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. Using the cash basis for Gas Distribution and Services rate regulated plans and the accrual method for all other plans, the Company's pension cost was $23.4 million (2006 – $20.1 million; 2005 – $11.6 million), and its OPEB cost was $6.9 million for 2007 (2006 – $7.0 million; 2005 – $5.9 million).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2007**	2006	2005	**2007**	2006	2005
Discount rate	**5.37%**	5.30%	6.21%	**5.27%**	5.24%	6.26%
Average rate of salary increases				**5.00%**	4.44%	4.00%
Average rate of return on pension plan assets	**4.50%**	4.50%	4.50%	**7.31%**	7.31%	7.31%

MEDICAL COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	5%	2017
Other Medical and Dental	5%	5%	2008
U.S. Plan	10%	5%	2013

A one percent increase in the assumed medical and dental care trend rate would result in an increase of $27.3 million in the accumulated post-employment benefit obligations and an increase of $2.4 million in benefit and interest costs. A one percent decrease in the assumed medical and dental care trend rate would result in a decrease of $22.0 million in the accumulated post-employment benefit obligations and a decrease of $1.9 million in benefit and interest costs.

MAJOR CATEGORIES OF PLAN ASSETS

(millions of dollars)	OPEB				Pension Benefits			
	2007			2006	**2007**			2006
Year ended December 31,	Target	Actual	Amount	Actual	Target	Actual	Amount	Actual
Equity securities	–	–	–	–	**60%**	**60.7%**	**794.9**	61.1%
Fixed income securities	**100%**	**85.4%**	**40.8**	86.9%	**40%**	**33.5%**	**438.6**	34.0%
Other	–	**14.6%**	**7.0**	13.1%	–	**5.8%**	**76.4**	4.9%
Total Assets	**100%**	**100%**	**47.8**	100%	**100%**	**100%**	**1,309.9**	100%

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

EXPECTED RATE OF RETURN ON PLAN ASSETS

	OPEB		Pension Benefits	
Year ended December 31,	**2007**	2006	**2007**	2006
Canadian Plans	**4.50%**	4.50%	**7.25%**	7.25%
U.S. Plan	**4.50%**	4.50%	**7.75%**	7.25%

The Company manages the investment risk of its pension funds by setting a long term asset mix policy for each fund after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

PLAN CONTRIBUTIONS BY THE COMPANY

(millions of dollars) Year ended December 31,	OPEB		Pension Benefits	
	2007	2006	**2007**	2006
Total contributions	**8.1**	11.0	**44.1**	0.7
Contributions expected to be paid in 2008	**6.9**	7.4	**25.9**	19.8

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

(millions of dollars) Year ended December 31,	2008	2009	2010	2011	2012	2013 - 2017
Expected future benefit payments	50.0	52.3	55.0	57.5	60.6	354.8

21. OTHER INVESTMENT INCOME

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Interest income	**32.7**	29.3	28.3
Gain on reduction of EEP ownership interest	**33.9**	–	24.5
Noverco preferred dividends income	**15.8**	15.6	16.8
OCENSA investment income	**24.7**	26.8	29.0
Net foreign currency gains	**26.2**	13.3	6.8
Allowance for equity funds used during construction	**15.1**	1.5	0.9
Hurricane insurance recoveries	**14.6**	6.0	–
Other	**32.1**	15.3	36.1
	195.1	107.8	142.4

22. CHANGES IN OPERATING ASSETS AND LIABILITES

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Accounts receivable and other	**(502.1)**	3.9	(441.4)
Inventory	**159.5**	134.1	(215.7)
Deferred amounts and other assets	**(134.6)**	(67.3)	(90.2)
Accounts payable and other[1]	**503.8**	43.5	394.8
Interest payable	**(5.9)**	12.5	(1.4)
	20.7	126.7	(353.9)

1 *Changes in construction payable are included in investing activities.*

23. RELATED PARTY TRANSACTIONS

EEP does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
EEP	**267.1**	244.9	184.7
Vector Pipeline	**4.8**	4.1	4.1
	271.9	249.0	188.8

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline and Vector Pipeline. EGD is charged market prices for these services:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Alliance Pipeline Canada	**21.3**	23.6	22.9
Alliance Pipeline US	**15.1**	14.1	17.5
Vector Pipeline	**25.0**	27.3	29.2
	61.4	65.0	69.6

CustomerWorks Limited Partnership (CustomerWorks), a joint venture, provided customer care services to EGD under an agreement having a five-year term which expired in 2007 and was not renewed. EGD was charged market prices for these services. CustomerWorks also rented an automated billing system from Enbridge Commercial Services Inc. (ECS), a subsidiary of the Company. Amounts charged by/(to) CustomerWorks are as follows:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
EGD	**26.3**	108.5	103.6
ECS	**(1.8)**	(8.1)	(8.7)
	24.5	100.4	94.9

Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts paid/(recovered) are as follows:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Purchases	**43.5**	29.2	48.1
Sales	**(4.1)**	(6.3)	(4.7)
	39.4	22.9	43.4

Enbridge Gas Services Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts paid are as follows:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Alliance Pipeline Canada	**8.5**	8.3	9.1
Vector Pipeline	**0.6**	0.6	0.7
	9.1	8.9	9.8

Enbridge Gas Services (US) Inc., has transportation commitments through 2015 on Alliance Pipeline US and Vector Pipeline. Amounts paid are as follows:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Alliance Pipeline US	**6.6**	6.9	7.1
Vector Pipeline	**15.6**	16.5	9.5
	22.2	23.4	16.6

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Purchases	**4.6**	17.0	9.7
Sales	**(5.5)**	(6.7)	–
	(0.9)	10.3	9.7

RECEIVABLE FROM AFFILIATE

The receivable from affiliate of $128.5 million (2006 – $158.8 million included in Accounts Receivable and Other), included in Deferred Amounts and Other Assets, initially resulted from the sale of Enbridge Midcoast Energy to EEP. During 2007, the original loan receivable was repaid and a new loan was entered into. The loan, denominated in U.S. dollars, bears interest at 8.4% and matures in 2017. Interest income related to the note was $10.0 million, $11.8 million and $11.7 million, in 2007, 2006 and 2005, respectively. The fair value of the receivable approximates its carrying value.

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable or at cost when required by regulatory agreement. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices being determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

24. COMMITMENTS AND CONTINGENCIES

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. On November 22, 2007 EGD was served with a Notice of Appeal by the Crown seeking a new trial before a different judge. The maximum possible fine upon conviction on all charges would have been approximately $5.0 million in the aggregate.

The Company has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The majority of the civil actions have been settled and the Company does not expect the outstanding civil actions to result in any material financial impact.

Harper Gardens Incident

In February 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A gas fitter in the home at the time of the explosion was seriously burned. Several public authorities are investigating the incident. EGD has also been named as defendant in civil actions related to the explosion, but does not expect these actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

EGD may incur future costs due to claims relating to alleged coal tar contamination at or near former manufactured gas plant (MPG) sites. In October 2002, a claim was filed for $55.0 million in damages relating to a certain MPG site. EGD filed a statement of defence in June 2003 denying liability. Although the Company believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance may be recovered through rates. As such, EGD does not believe the outcome will have any material financial impact.

GST Overpayment

In December 2007, EGD discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment is approximately $40 million and is included in accounts receivable. EGD expects that it will recover the overpayment from CRA.

CAPLA CLAIM

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced a class action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Plaintiffs filed a motion to establish a cause of action which is one of the requirements to have the motion certified as a class action under the *Class Proceedings Act (Ontario)*. The motion was dismissed by the Ontario District Court in late 2006. The Plantiff appealed the decision and the appeal was heard by the Ontario Court of Appeal on December 18, 2007. The decision of the Court of Appeal has not been released. The Company believes it has a sound defence and intends to defend the claim. Since the outcome is indeterminable, the Company has made no provision at this time for any potential liability.

ENBRIDGE ENERGY COMPANY, INC.

Enbridge Energy Company, Inc. (EEC), a subsidiary of the Company, is the general partner of EEP. EEC's former subsidiary Enbridge Midcoast Energy Inc. (Midcoast) has been assessed by the U.S. Internal Revenue Service (IRS) for US$4.5 million in taxes, interest and penalties for its 1999 through 2001 taxation years. Midcoast has paid all amounts and has filed a claim for refund of the full amount. The IRS has challenged Midcoast's tax treatment of its 1999 acquisition of several partnerships that owned a natural gas pipeline system in Kansas (these assets were sold to EEP in 2002 and subsequently sold by EEP in 2007). The IRS position, if sustained, could decrease the U.S. tax basis for the pipeline assets, which could reduce Enbridge's earnings by up to approximately US$60.0 million, although the immediate cash tax impact would be significantly less. Enbridge believes the tax treatment of the acquisition and related tax deductions claimed were appropriate. Enbridge initiated proceedings in U.S. District Court (Houston) in 2006 to litigate this matter.

OTHER TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal actions and proceedings which arise in the normal course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

COMMITMENTS

The Company has signed contracts for the purchase of pipe and other materials totaling $947.6 million, to be used in the construction of several Liquids Pipelines projects including the Southern Lights project, the Waupisoo Pipeline, the Alberta Clipper project, the Southern Access Expansion and Extension projects, the Hardisty Terminal project as well as the Line 4 Extension project.

25. GUARANTEES

EEC, as the general partner of EEP, has agreed to indemnify EEP from and against substantially all liabilities including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

In addition, in the event of default, EEC is subject to recourse with respect to US$124.0 million of EEP's long-term debt at December 31, 2007 (2006 – US$155.0 million).

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, Enbridge enters into a wide variety of agreements which provide for indemnification to third parties. Enbridge cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, Enbridge has not made any significant payments under these indemnification provisions. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples where such indemnification obligations have been issued include:

Sale Agreements for Assets or Businesses

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

26. SUBSEQUENT EVENT

On February 13, 2008 Enbridge announced it is evaluating strategic alternatives for monetizing its investment in CLH. Earnings generated by the CLH investment in 2007 were $65.6 million (2006 – $54.5 million; 2005 – $61.6 million) and cash flows were $58.2 million (2006 – $56.2 million; 2005 – $36.5 million). The book value of the CLH investment at December 31, 2007 was $626.4 million which does not include unrealized foreign exchange gains and related unrealized net investment hedge gains of $32.9 million recorded in AOCI.

27. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS AND COMPREHENSIVE INCOME

(millions of dollars, except per share amounts)

Year ended December 31,	**2007**	2006	2005
Earnings under Canadian GAAP	**707.1**	622.3	562.9
Stock-based compensation[1]	–	–	(16.6)
Earnings under U.S. GAAP	**707.1**	622.3	546.3
Other comprehensive income/(loss) under Canadian GAAP	**(197.4)**	36.0	(32.0)
Unrealized net gain/(loss) on cash flow hedges[3]	–	(64.2)	72.3
Underfunded pension adjustment (net of tax)[4]	**23.3**	–	–
Comprehensive income under U.S. GAAP	**533.0**	594.1	586.6
Earnings per common share under U.S. GAAP	**1.97**	1.81	1.65
Diluted earnings per common share under U.S. GAAP	**1.95**	1.79	1.63

FINANCIAL POSITION

(millions of dollars)	2007		2006	
December 31,	Canada	United States	Canada	United States
Assets				
Cash and cash equivalents[3,6]	**166.7**	**214.4**	139.7	347.0
Accounts receivable and other[1,3,4,6]	**2,388.7**	**3,118.4**	2,045.6	2,920.0
Inventory[3,6]	**709.4**	**817.3**	868.9	1,005.0
	3,264.8	**4,150.1**	3,054.2	4,272.0
Property, plant and equipment, net[3,6]	**12,597.6**	**17,999.4**	11,264.7	15,628.4
Long-term investments[3,6]	**2,076.3**	**1,253.1**	2,299.4	1,368.8
Deferred amounts and other assets[2,3,4,5,6]	**1,182.0**	**1,653.5**	924.5	1,540.5
Intangible assets[6]	**212.0**	**302.4**	241.5	348.0
Goodwill[6]	**388.0**	**725.1**	394.9	803.2
Future income taxes[6]	**186.7**	**187.3**	200.1	200.1
	19,907.4	**26,270.9**	18,379.3	24,161.0
Liabilities and Shareholders' Equity				
Short-term borrowings	**545.6**	**545.5**	807.9	807.9
Accounts payable and other[1,3,4,6]	**2,213.8**	**3,195.1**	1,723.8	2,818.6
Interest payable[6]	**89.1**	**109.8**	95.1	108.4
Current maturities and short-term debt[6]	**605.2**	**632.7**	537.0	537.0
Current portion of non-recourse debt[3,6]	**61.1**	**60.9**	60.1	83.2
	3,514.8	**4,544.0**	3,223.9	4,355.1
Long-term debt[4]	**7,729.0**	**10,600.5**	7,054.0	7,054.0
Non-recourse long-term debt[3,6]	**1,508.4**	**1,508.4**	1,622.0	4,029.6
Other long-term liabilities[3,5,6]	**253.9**	**479.2**	91.1	310.8
Future income taxes[2,3,4,5,6]	**975.6**	**1,545.7**	1,062.5	1,696.4
Non-controlling interests[6]	**650.5**	**2,355.2**	715.2	2,163.9
	14,632.2	**21,033.0**	13,768.7	19,609.8
Shareholders' Equity				
Preferred shares	**125.0**	**125.0**	125.0	125.0
Common shares	**3,026.5**	**3,026.5**	2,416.1	2,416.1
Contributed surplus	**25.7**	**–**	18.3	–
Retained earnings	**2,537.3**	**2,504.4**	2,322.7	2,242.8
Additional paid in capital	**–**	**69.6**	–	62.2
Foreign currency translation adjustment[4]	**–**	**–**	(135.8)	–
Accumulated other comprehensive loss[4,5]	**(285.0)**	**(333.3)**	–	(159.2)
Reciprocal shareholding	**(154.3)**	**(154.3)**	(135.7)	(135.7)
	5,275.2	**5,237.9**	4,610.6	4,551.2
	19,907.4	**26,270.9**	18,379.3	24,161.0

1 *Stocked-based Compensation*
Effective January 1, 2006, the Company adopted Financial Accounting Standard 123 Revised 2004 (FAS 123R) Share Based Payment, *on a modified prospective basis for U.S. GAAP purposes. FAS 123R requires the use of the fair value method to measure compensation expense for the Company's Fixed Stock Options (FSOs) and PBSOs issued after January 1, 2006, as well as for the portion of awards for which the requisite service has not been*

performed that are outstanding as of January 1, 2006. FAS 123R also requires the use of the fair value method for awards settled in cash, including the company's PSUs and RSUs.

The Company had previously adopted the fair value recognition provisions of the former FAS 123, Share Based Payment, *effective January 1, 2003, resulting in the recognition of stock based compensation expense using the fair value method for FSOs and PBSOs issued subsequent to that date.*

2 *Future Income Taxes*

Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. At December 31, 2007, a deferred tax liability of $572.7 million (2006 – $648.7 million) is recorded for U.S. GAAP purposes and reflects the difference between the carrying value and the tax basis of property, plant and equipment. Regulated companies following the taxes payable method are not required to record this additional tax liability under Canadian GAAP. To recover the additional deferred income taxes recorded under U.S. GAAP through the ratemaking process, it would be necessary to record incremental revenue of $785.6 million (2006 – $926.7 million).

3 *Accounting for Joint Ventures*

U.S. GAAP requires the Company's investments in joint ventures to be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity.

4 *Accumulated Other Comprehensive Loss*

The only Canadian – U.S. GAAP difference in accumulated other comprehensive loss is the underfunded status of the pension and OPEB plans. The Company estimates that approximately $1.3 million related to pension and OPEB plans at December 31, 2007 will be reclassified into earnings during the next twelve months.

Financial instruments are now recognized in Canadian GAAP in substantially the same manner as U.S. GAAP. As a result of the change in Canadian accounting, certain comparative balances have been reclassified for U.S. GAAP purposes, including the recognition of regulated non-financial instruments and offsetting regulatory liabilities as well as OCI from equity investees. In addition, transaction costs arising from the issuance of debt are now recorded net against the related long-term debt. For U.S. GAAP, these transaction costs are reclassified to deferred amounts and other assets.

5 *Pension Funding Status*

The Company adopted FAS 158, Employers' Accounting for Defined Pension and Other Postretirement Plans, *effective December 31, 2006. FAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB as an asset or liability and to recognize changes in the funded status in the period in which they occur through comprehensive income. FAS 158 adjustments resulted in an increase in the net liability of $73.1 million (2006 – $110.1 million) for the underfunded status of the plans, a decrease in deferred tax liability of $24.8 million (2006 – $38.5 million) and an increase in accumulated other comprehensive loss of $48.3 million (2006 – $71.6 million). As required by FAS 158, the Company will change the measurement date of its defined benefit pension plan from September 30 to December 31, effective the year ended 2008.*

6 *Consolidation of a Limited Partnership*

Effective January 1, 2006, the Company adopted, without restatement of prior periods, EITF 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights. *As a result of adopting EITF 04-5, the Company is consolidating its 15.1% interest in Enbridge Energy Partners for U.S. GAAP purposes, resulting in an increase to both assets and liabilities of $5,932.7 million (2006 – $5,084.8 million) and no changes to equity and earnings.*

7 *Uncertain Tax Positions*

On January 1, 2007, the Company adopted FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. *FIN 48 addresses the threshold for recognizing a tax position in the financial statements. The adoption of FIN 48 did not have an impact on the consolidated financial statements.*

NEW ACCOUNTING STANDARDS

Fair Value Measurements

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements*. The Statement defines fair value, establishes a framework for measuring fair value in the context of GAAP and expands the disclosure surrounding fair value measurement. In January 2008, the FASB deferred the implementation of this standard indefinitely for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis until January 1, 2009. The requirements of this standard will be effective for the Company beginning on January 1, 2008.

Fair Value Option for Assets and Liabilities

In February 2007, the FASB issued Statement No. 159, *Fair Value Option for Financial Assets and Liabilities*. This standard provides companies with an option to measure, at specified election dates, certain financial assets and liabilities at fair value. Changes in fair value are recognized in earnings. The requirements of this standard will be effective for the Company beginning on January 1, 2008.

Management does not expect the adoption of these standards to significantly impact the financial statements.

SUPPLEMENTARY INFORMATION (UNAUDITED)

QUARTERLY SHARE TRADING INFORMATION

The Toronto Stock Exchange

2007 (dollars)	**First**	**Second**	**Third**	**Fourth**
High	**41.48**	**38.35**	**38.74**	**40.97**
Low	**36.50**	**35.21**	**33.62**	**35.75**
Close	**37.66**	**35.90**	**36.44**	**40.01**
Volume (millions)	**60.6**	**45.8**	**47.3**	**50.1**

2006 (dollars)	First	Second	Third	Fourth
High	37.00	35.24	37.08	41.45
Low	33.42	31.75	34.44	34.50
Close	33.60	33.97	36.07	40.27
Volume (millions)	41.7	57.6	34.0	40.4

The New York Stock Exchange

2007 (U.S. dollars)	**First**	**Second**	**Third**	**Fourth**
High	**35.40**	**36.15**	**37.13**	**44.29**
Low	**30.93**	**32.06**	**31.26**	**36.20**
Close	**32.65**	**33.78**	**36.67**	**40.43**
Volume (millions)	**9.1**	**11.7**	**12.6**	**15.6**

2006 (U.S. dollars)	First	Second	Third	Fourth
High	32.29	32.01	33.34	36.00
Low	28.64	28.06	30.33	30.32
Close	28.87	30.57	32.30	34.40
Volume (millions)	8.7	12.5	8.6	8.7

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

FINANCIAL AND OPERATING INFORMATION[1]

(millions of dollars, except where otherwise noted)	**2007**	2006	2005	2004	2003
Earnings Applicable to Common Shareholders					
Liquids Pipelines	**287.2**	274.2	229.1	219.9	213.5
Gas Pipelines	**69.7**	61.2	59.8	53.8	70.1
Sponsored Investments	**96.9**	86.8	64.8	66.2	234.3
Gas Distribution and Services	**184.1**	178.2	178.8	313.1	153.6
International	**95.1**	83.2	87.4	73.6	72.3
Corporate	**(32.8)**	(68.2)	(63.9)	(81.3)	(76.6)
Earnings applicable to common shareholders	**700.2**	615.4	556.0	645.3	667.2
Adjusted operating earnings applicable to common shareholders[2]	**636.5**	592.9	537.2	491.1	495.5
Cash Flow Data					
Cash provided by operating activities	**1,378.7**	1,297.7	947.0	886.7	368.5
Additions to property, plant and equipment	**2,299.2**	1,185.3	724.1	496.4	391.3
Acquisitions and long-term investments	**20.3**	463.7	178.5	850.5	128.8
Common share dividends	**452.3**	403.1	361.1	315.8	283.9
Operating Data					
Liquids Pipelines – Deliveries (thousands of barrels per day)					
Enbridge System[3]	**2,005**	2,013	1,872	2,001	1,864
Athabasca System[4]	**164**	190	142	149	134
Spearhead Pipeline	**103**	82	–	–	–
Olympic Pipeline	**284**	289	–	–	–
Gas Pipelines – Average Daily Throughput Volume (millions of cubic feet per day)					
Alliance Pipeline US	**1,598**	1,592	1,597	1,581	1,588
Vector Pipeline	**1,034**	1,015	1,033	997	991
Enbridge Offshore Pipelines	**2,060**	2,153	2,102	–	–
Gas Distribution and Services[5]					
Volumes (billions of cubic feet)	**418**	408	438	575	458
Number of active customers (thousands)	**1,902**	1,852	1,805	1,756	1,679
Degree day deficiency[6]					
Actual	**3,659**	3,355	3,750	5,052	4,029
Forecast based on normal weather	**3,617**	3,745	3,747	4,849	3,565

1 *As a result of the elimination of the quarter lag basis of consolidation, Gas Distribution and Services financial and operating information for 2004 reflects earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution (EGD), Noverco and other gas distribution entities. The 2003 data includes earnings for the 12 months ended September 30, 2003 for these entities, while 2005 and 2006 information is for the 12 months ended December 31, 2005 and 2006 for these entities.*

2 *Adjusted operating earnings applicable to common shareholders represents earnings applicable to common shareholders adjusted for non-operating factors primarily including non-operating gains and losses, the impact of weather, regulatory disallowances and impacts of tax rate changes. Adjusted operating earnings applicable to common shareholders is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers. Management believes the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends. Earnings for 2004 and 2003 have been adjusted to eliminate the quarter lag basis of consolidation described above.*

3 *Enbridge system includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border and Line 9 in Eastern Canada.*

4 *Volumes are for the Athabasca mainline only and do not include laterals on the Athabasca System.*

5 *Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

6 *Degree day deficiency is a measure of coldness which is indicative of volumetric requirements of natural gas utilized for heating purposes. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto area.*

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

SHAREHOLDER AND INVESTOR INFORMATION

(per share amounts in dollars)	**2007**	2006	2005	2004	2003
Shares Outstanding (millions)					
Weighted average common shares outstanding	**355.3**	340.0	337.4	334.5	330.9
Diluted weighted average common shares outstanding	**358.3**	343.3	341.2	337.2	333.8
Common Share Trading (TSX)					
High	**41.48**	41.45	38.82	30.08	27.07
Low	**33.62**	31.75	28.59	23.63	20.48
Close	**40.01**	40.27	36.34	29.85	26.85
Volume (millions)	**203.8**	173.7	211.3	155.4	150.2
Per Common Share Data					
Earnings applicable to common shareholders	**1.97**	1.81	1.65	1.93	2.02
Adjusted operating earnings applicable to common shareholders[1]	**1.79**	1.74	1.59	1.47	1.50
Dividends paid on common shares	**1.23**	1.15	1.04	0.92	0.83
Financial Ratios					
Return on average shareholders' equity[2]	**13.6%**	13.9%	13.2%	17.0%	19.0%
Return on average capital employed[3]	**7.0%**	7.0%	6.9%	8.3%	8.3%
Debt to debt plus shareholders' equity[4]	**66.5%**	68.6%	68.9%	67.1%	68.7%
Debt to average capital employed[5]	**68.3%**	71.1%	71.0%	67.2%	66.1%
Earnings coverage of interest[6]	**2.4x**	2.4x	2.4x	2.8x	2.7x
Dividend payout ratio[7]	**68.7%**	66.1%	65.2%	62.3%	55.3%

1 *Adjusted operating earnings applicable to common shareholders represents earnings applicable to common shareholders adjusted for non-operating factors primarily including non-operating gains and losses, the impact of weather, regulatory disallowances and impacts of tax rate changes. Adjusted operating earnings applicable to common shareholders is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers. Management believes the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends. Earnings for 2004 and 2003 have been adjusted to eliminate the quarter lag basis of consolidation described above.*

2 *Earnings applicable to common shareholders divided by average shareholders' equity (weighted monthly during the year).*

3 *Sum of after-tax earnings (including earnings from discontinued operations) and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

5 *Total debt (including short-term borrowings) divided by average capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

6 *Earnings before taxes and interest expenses divided by interest expense (including capitalized interest).*

7 *Dividends per common share divided by adjusted operating earnings per common share applicable to common shareholders.*

ENBRIDGE BUSINESSES

LIQUIDS PIPELINES

Enbridge Pipelines Inc. (100%)

Enbridge Pipelines (NW) Inc. (100%)

Enbridge Pipelines (Athabasca) Inc. (100%)

Enbridge Pipelines (Toledo) Inc. (100%)

Enbridge Southern Lights LLC (100%)

Enbridge Midstream Inc. (100%)

Gateway Pipeline Limited Partnership (100%)

Mustang Pipe Line Partners (30%)

Chicap Pipe Line Company (22.8%)

Frontier Pipeline Company (77.8%)

CCPS Transportation L.L.C. (Spearhead Pipeline) (100%)

Olympic Pipe Line Company (65%)

Hardisty Caverns Limited Partnership (50%)

GAS PIPELINES

Alliance Pipeline L.P. (U.S. portion) (50%)

Vector Pipeline Limited Partnership (60%)

Enbridge Offshore Pipelines, L.L.C. (22% - 100%)

SPONSORED INVESTMENTS

Enbridge Energy Partners, L.P. (15.1%)

- Lakehead System
- North Dakota System
- Mid-Continent System
- Various Natural Gas Systems

Enbridge Income Fund (72.3% overall economic interest)

- Enbridge Pipelines (Saskatchewan) Inc. (100%)
- Alliance Pipeline Limited Partnership (Canadian portion) (50%)
- SunBridge Wind Power Project (50%)
- Magrath Wind Power Project (33.3%)
- Chin Chute Wind Power Project (33.3%)
- NRGreen Power Limited Partnership (50%)

GAS DISTRIBUTION AND SERVICES

Enbridge Gas Distribution (100%)

- St. Lawrence Gas Company, Inc.

Gazifere Inc. (100%)

Niagara Gas Transmission Limited (100%)

Noverco Inc. (32.1%), which owns:

- Gaz Métro Limited Partnership (71%), which owns:
  - Vermont Gas Systems, Inc. (100%)
  - TQM Pipeline and Company, Limited Partnership (50%)
  - Portland Natural Gas Transmission System (38.3%)

Enbridge Gas New Brunswick Limited Partnership (70.8%)

CustomerWorks Limited Partnership (70%)

Enbridge Commercial Services Inc. (100%)

Aux Sable Liquids Products Inc. (42.7%)

Enbridge Gas Services (U.S.) Inc. (100%)

Enbridge Gas Services Inc. (100%)

Inuvik Gas Ltd. (33.3%)

Tidal Energy Marketing Inc. (100%)

Tidal Energy Markets (U.S.) L.L.C. (100%)

Value Creation Inc. (strategic alliance)

NetThruPut Inc. (52%)

Enbridge Ontario Wind Power LP (100%)

FuelCell Energy (strategic alliance)

Enbridge Solutions Inc. (100%)

Enbridge Electric Connections Inc. (100%)

Rabaska Limited Partnership (33%)

INTERNATIONAL

Oleoducto Central S.A. (24.7%)

Compañia Logistica de Hidrocarburos CLH, S.A. (25%)

Enbridge Technology Inc. (100%)

AWARDS & RECOGNITION IN 2007

CORPORATE SOCIAL RESPONSIBILITY

Dow Jones Sustainability Index (North America): Enbridge Inc. was named to the Dow Jones Sustainability Index North America (DJSI North America) for 2007/2008. The DJSI tracks the financial performance of leading sustainability-driven companies worldwide. The DJSI North America includes the top 20% in each of 57 sectors out of the 600 largest North American companies in the Dow Jones Global Index.

Energy Person of the Year: The Energy Council of Canada named Enbridge President and Chief Executive Officer Pat Daniel the 2007 recipient of the Canadian Energy Person of the Year. The award pays tribute to leaders in Canada who have made a significant impact at both the national and international level with respect to energy.

Newsweek International's 100 Most Adaptable Companies: Enbridge ranked 26th on the list of the 100 companies best able to adapt to global warming. The list is based on an analysis of 1,800 companies by *Corporate Knights* magazine and Innovest Strategic Value Advisors. The companies were ranked exclusively for *Newsweek* magazine on how effectively they manage environmental risks and opportunities relative to their industry peers.

Fortune America's Most Admired Companies: Enbridge Energy Partners was ranked fourth among pipeline companies for America's Most Admired Companies for 2007, based on eight criteria including investment value and social responsibility. Enbridge Energy Partners ranked Number One among its peers in the Social Responsibility category.

Canada's Top 100 Employers: For the third year in a row, Enbridge was selected for the 2008 edition of Canada's Top 100 Employers, and was again chosen one of Alberta's Top 25 Employers.

The Best 50 Corporate Citizens in Canada for 2007: Enbridge was included in *Corporate Knights* magazine's sixth annual listing of best corporate citizens.

Alberta Venture Most Respected Corporations: For the fourth year in a row, Enbridge was recognized as one of Alberta's Most Respected Corporations in *Alberta Venture* magazine's annual awards.

Jantzi's A- rating for CSR management: *Maclean's* magazine and Jantzi Research awarded Enbridge a grade of 'A-' for the Company's 2007 Corporate Social Responsibility performance.

TSX 200 Climate Disclosure Leadership Index (CDLI): Named to the CDLI by the Conference Board of Canada, Enbridge placed fifth out of 16 companies recognized for their commitment to rigorous and transparent reporting of their greenhouse gas emissions and the effectiveness of programs put in place to reduce overall emissions.

Gold Champion Level Reporter: The Canadian Standards Association (CSA)—Canadian GHG Registry gave Enbridge the highest level of achievement—Gold Champion Level Reporter—for the Company's most recent submission.

Natural Gas STAR Award—Processing Partner of the Year: The U.S. Environmental Protection Agency (EPA) STAR program to reduce methane emissions named Enbridge Energy Partners, Inc. its 2007 Processing Partner of the Year for consistent engagement in the program. Since joining the STAR program in 2003, Enbridge Energy Partners has submitted an annual report each year and in 2006 reported the highest normalized reductions of all STAR's processing partners.

Corporate Philanthropist Award (Calgary): Enbridge received the Corporate Philanthropist Award at the annual Philanthropy Day Luncheon in Calgary. This award is recognized as one of the most prestigious corporate awards in Calgary.

United Way Thanks a Million Award (Canada): For the eighth consecutive year, Enbridge received the United Way's Thanks a Million Award that recognizes organizations that raise $1 million or more nationally for United Ways across Canada.

INVESTOR INFORMATION

Common and Preferred Shares
The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preferred Shares, Series A, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.A".

Registrar and Transfer Agent in Canada
CIBC Mellon Trust Company
P.O. Box 7010,
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Telephone: (800) 387-0825
or (416) 643-5000 outside of North America
Internet: www.cibcmellon.com/investorinquiry
CIBC Mellon Trust Company also has offices in Halifax, Montreal, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States
BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310
Toll free: (800) 387-0825
Internet: www.cibcmellon.com/investorinquiry

Preferred Securities
Enbridge Inc. redeemed all of its Preferred Securities, Series D, effective February 15, 2007. The registrar and transfer agent is Computershare Trust Company of Canada.

Debentures
The registrar and trustee for Enbridge Debentures is Computershare Trust Company of Canada, with offices in Montreal, Toronto, Winnipeg, Edmonton and Vancouver.

Auditors
PricewaterhouseCoopers LLP

Dividend Reinvestment and Share Purchase Plan, and Dividend Direct Deposit
Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. Effective with dividends payable on March 1, 2008, participants in the Plan will receive a two per cent discount on the purchase of Common Shares with reinvested dividends. The Company also offers Dividend Direct Deposit which enables shareholders to receive dividends by electronic fund transfer to the bank account of their choice in Canada. Details may be obtained from the Investor Information section of the Enbridge website at or by contacting CIBC Mellon Trust Company at the location listed above.

New York Stock Exchange Disclosure Differences
As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies under NYSE listing standards. This disclosure can be obtained from the *U.S. Compliance* subsection of the Corporate Governance section of the Enbridge website at www.enbridge.com.

Form 40-F
The Company files annually with the U.S. Securities and Exchange Commission a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company.

Registered Office
Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920
Internet: www.enbridge.com

Le présent document est disponible en français.

Shareholder Inquiries

If you have inquiries regarding the following:

- Dividend Reinvestment and Share Purchase Plan
- change of address
- share transfer
- lost certificates
- dividends
- duplicate mailings

Please contact the registrar and transfer agent – CIBC Mellon Trust Company in Canada or BNY Mellon Shareowner Services in the United States.

Other Investor Inquiries

If you have inquiries regarding the following:

- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations

Please contact Enbridge Investor Relations or visit Enbridge's website at www.enbridge.com.

Investor Relations

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804

Annual and Special Meeting

The Annual and Special Meeting of Shareholders will be held at the Boyce Theatre, Calgary Stampede, 10 Corral Trail S.E., Calgary, Alberta at 1:30 p.m. MDT on Wednesday, May 7, 2008.

2008 Dividend Information for Common Shares and Preferred Shares, Series A[1]

	1st Q	2nd Q	3rd Q	4th Q
Record date	Feb. 15	May 15	Aug. 15	Nov. 14
Payment date	March 1	June 1	Sept. 1	Dec. 1
Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date	Feb. 8	May 8	Aug. 8	Nov. 8
Common Share Purchase Plan cut-off date for DRIP	Feb. 25	May 26	Aug. 25	Nov. 24

1 *Dividend dates are subject to the dividends being declared by the Board of Directors.*

Designed and Produced by Karo Group Calgary. Printed in Canada by Blanchette Press.

Mixed Sources

FSC

Printed on post-consumer recycled paper, a portion of which was manufactured with wind energy.

ENBRIDGE

Enbridge common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the trading symbol "ENB".

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920
Toll free: (800) 481-2804
www.enbridge.com

NBRIDGE INCOME FUND | ANNUAL REPORT 2007

THREE SOLID BUSINESSES.
ONE STABLE INVESTMENT.

ENBRIDGE

ENBRIDGE INCOME FUND

The Enbridge Income Fund is underpinned by:

NATURAL GAS 50% interest in the Alliance Canada pipeline.

CRUDE OIL AND LIQUIDS 100% interest in the Saskatchewan System.

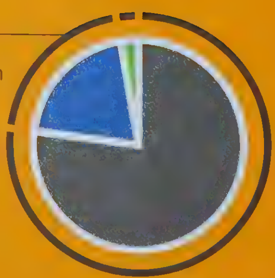
GREEN POWER assets which include a 50% interest in NRGreen, a generator of electric power from waste heat, and interests in three wind power projects in western Canada.

Revenues By Core Business Asset

77.2% Alliance Canada System

20.1% Saskatchewan System

2.7% Green Power



HIGHLIGHTS

OPERATING AND FINANCIAL HIGHLIGHTS

(millions of dollars except where otherwise noted)

Year ended December 31,	2007	2006
Average Daily Throughput Volume		
Alliance Canada *(millions of cubic feet per day)*	**1,598.0**	1,592.0
Saskatchewan System [1] *(thousands of barrels per day)*		
Westspur System	**157.2**	155.2
Saskatchewan Gathering System	**109.6**	103.8
Weyburn System	**35.0**	37.3
Virden System	**24.2**	20.7
Green Power [2] *(thousands of megawatt hours produced)*	**285.0**	52.2
Revenues	**270.8**	254.4
Earnings	**21.1**	35.3
Per Unit *(dollars per unit)*	**0.61**	1.02
Cash Available for Distribution	**73.5**	74.3
Cash Distributions Declared	**69.6**	67.3
Cash Distributions Declared Per Unit *(dollars per unit)*		
Ordinary and Subordinated Units	**0.9600**	0.9259
Enbridge Commercial Trust Preferred Units	**0.9600**	0.9259

1 *Totals are not presented because the same volumes can be transported through a combination of pipelines comprising the Saskatchewan System.*

2 *Wind assets were acquired on October 1, 2006. NRGreen's Kerrobert waste heat facility began operations December 29, 2006.*

Enbridge Income Fund is a premier Canadian income fund with a strong track record for generating predictable and moderately growing distributions.

Cash Distributions per Unit[1]

(dollars per unit)

1 *Distributions declared monthly.*

LETTER TO UNITHOLDERS

Gordon G. Tallman
Chair,
Board of Trustees

James A. Schultz
President, Enbridge
Management Services Inc.

Enbridge Income Fund's portfolio of low risk energy infrastructure assets remains a solid foundation on which to build value for investors.

In 2007, Enbridge Income Fund continued to build on its strong track record of delivering consistent cash flow for distributions. The Fund's asset base remains well-positioned in 2008 to continue delivering value for income-oriented investors through generating reliable, low-risk cash flow and moderate growth. The ongoing growth in our alternative energy assets also offers an increasingly compelling environmentally friendly investment profile.

The Fund generated earnings of $21.1 million in 2007. Cash available for distribution in 2007 of $73.5 million was in line with last year. Cash distributions declared of $69.6 million represented 94.7% of cash available for distribution and were modestly higher than 2006.

The Fund's ability to generate stable, reliable income for its unitholders comes from its solid base of high quality energy infrastructure assets. The Fund's investment in the Alliance Canada natural gas pipeline and the Saskatchewan System crude oil gathering and feeder pipeline system are both underpinned by regulatory and contractual arrangements that support its stable, low-risk business model. The Fund's Green Power segment includes interests in several wind and waste heat power generation businesses that produce electricity via alternative energy sources, and sell that power under long-term contracts with low-risk counterparties.

Our existing assets offer attractive organic growth potential and we are excited about the opportunities we were able to act on in 2007 and the results that we can look forward to in 2008.

ALLIANCE CANADA

In 2007, Alliance Canada delivered a record average of 1.598 billion cubic feet per day of natural gas for its shippers. This accomplishment was achieved through effective maintenance and line pack management.

Alliance Canada uses environmentally friendly, state-of-the-art technology to provide a high pressure, liquid-rich, bullet line service from western Canada to the Chicago market hub. Alliance Canada has successfully implemented a number of optimization projects and is well-positioned to continue leveraging the competitive advantages of its assets into further optimization and growth opportunities.

In September 2007, Alliance Canada received approval from the National Energy Board for its $30.3 million BCX Expansion Project, which will enhance its capacity for natural gas receipts originating in northeastern British Columbia and enable existing shippers to increase gas nominations at receipt points in B.C. Construction is expected to commence in early 2008 with an expected in-service date in late 2008.

In the longer term, Alliance also has some very cost-effective and competitive expansion capability which provides potential upside related to Northern gas development.

SASKATCHEWAN SYSTEM

The Saskatchewan System continues to be focused on meeting increased crude oil production and growing demand for pipeline capacity in its service area. The Westspur expansion project, which will increase the system's capacity by approximately 20% at an expected cost of $30.5 million, is central to the Saskatchewan System's current growth plans. Construction on this project began in November 2007 and the expanded pipeline is expected to be in service by the second quarter of 2008.

We believe the Saskatchewan System also has promising future growth opportunities as we look toward completing our current phase of expansions. The Saskatchewan System is uniquely positioned to take advantage of the increased production in southeastern Saskatchewan from the Bakken play. This reservoir is relatively new and reports of development completed to date indicate significant demand for additional crude oil transportation capacity in the area.

GREEN POWER

In 2007, NRGreen completed the commissioning of its Loreburn and Estlin, Saskatchewan waste heat electricity generation facilities. These facilities, along with a third facility at Alameda, Saskatchewan are set to commence operations in mid 2008. Electricity is generated by harnessing the waste heat produced by Alliance Canada's gas turbines at its compressor stations and converting it to electrical energy. Combined with the existing waste heat recovery facility at Kerrobert, Saskatchewan, NRGreen will have approximately 20 megawatts of environmentally friendly power generation that will be sold under long-term contracts to SaskPower.

The Fund's Wind Power assets are also supported by long-term contracts to sell electricity into the provincial grids in Alberta and Saskatchewan. In 2007, the performance of the wind power assets was driven by higher than anticipated wind resource.

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. While the Tax Fairness Plan also imposes certain limits on growth for income trusts aiming to avoid early imposition of the new distribution tax, we are confident that the growth plans outlined above can be executed even within these limitations.

With our portfolio of high-quality, long-lived assets that deliver sustainable and predictable cash flows, and the organic growth projects we have underway, Enbridge Income Fund remains positioned to deliver investor value into the future. Complementing the strength of our assets is our sponsorship and strategic alignment with Enbridge Inc., a company with one of the strongest track records for developing and managing energy infrastructure using a low-risk business model.

Looking ahead to 2008, we are confidently focused on executing our slate of real, demand-driven organic growth projects to support continued predictable and moderately growing cash flow for distributions.

Gordon G. Tallman
Chair, Board of Trustees

James A. Schultz
President, Enbridge Management Services Inc.

Enbridge Income Fund carries out its activities through three business segments: Alliance Canada, Saskatchewan System and Green Power*.

***includes NRGreen – Electricity Generation, and Wind Power – Electricity Generation**

ALLIANCE CANADA

NATURAL GAS TRANSPORTATION

Enbridge Income Fund has a 50% interest in the Canadian portion of the larger Alliance System, which includes the Alliance Canada and Alliance US pipelines, and which transports natural gas from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois.

ALLIANCE CANADA

- consists of approximately 1,560 kilometres of the Alliance System, beginning near Gordondale, Alberta and connecting to Alliance US at the Canada/U.S. border near Carnduff, Saskatchewan
- includes the Alliance System's lateral pipelines, which connect the mainline to a number of upstream receipt points, primarily at natural gas processing facilities in northwestern Alberta and northeastern British Columbia, and related infrastructure
- the Alliance System is designed to transport 1,325 million cubic feet per day of natural gas on a firm basis
- shippers have firm transportation service agreements (TSAs) with both Alliance Canada and Alliance US, which have an initial 15-year term expiring in November 2015, and which provide for 98.5% of the Alliance System's available firm transportation capacity. The TSAs are designed to provide Alliance Canada with a steady and predictable cash flow stream through 2015.

TRANSPORTING NATURAL GAS TO THE U.S.

The Alliance System, which includes Alliance Canada and Alliance US, transports natural gas from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago.

SASKATCHEWAN SYSTEM

CRUDE OIL AND LIQUIDS TRANSPORTATION

Enbridge Income Fund has a 100% interest in the Saskatchewan System, which consists of crude oil and liquids pipelines that connect producing fields in southern Saskatchewan and southwestern Manitoba with Enbridge Inc.'s mainline pipeline to the U.S.

THE SASKATCHEWAN SYSTEM

- includes the Saskatchewan Gathering, Westspur, Weyburn and Virden pipeline systems
- has approximately 296 kilometres of trunk lines, 1,900 kilometres of gathering pipeline, and related terminals and storage facilities
- has capacity on the Saskatchewan Gathering and Westspur Systems of 190,000 barrels per day, and capacity on the Weyburn and Virden Systems of 47,000 and 37,000 barrels per day, respectively.

CONNECTING PRODUCTION WITH MAJOR PIPELINES

The Saskatchewan System connects crude oil production in southern Saskatchewan and southwestern Manitoba with Enbridge Inc.'s mainline pipeline, for transportation to the U.S.

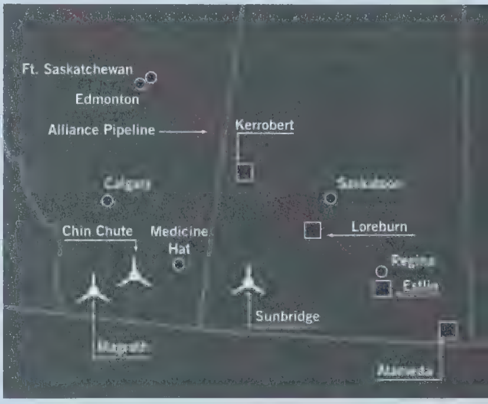
GREEN POWER

ELECTRICITY GENERATION

Enbridge Income Fund has interests in environmentally friendly power generation projects. These consist of three wind power projects in western Canada that generate electricity from wind turbines, and NRGreen, which generates electricity using waste heat from Alliance Canada's compressor stations.

Wind Power consists of

- SunBridge Project (50% interest), 11 megawatts (MW) capacity
- Magrath and Chin Chute Projects (33% interest in each), 30 MW capacity each
- long-term power purchase agreements with investment grade counterparties.



NRGreen (50% interest) consists of

- a 5 MW Kerrobert waste heat recovery facility in Saskatchewan
- waste heat recovery facilities at Loreburn, Estlin and Alameda (5.1 MW each), currently under construction
- long-term power purchase agreements with SaskPower
- opportunities for additional sites at other locations along the Alliance Canada System.

GENERATING GREEN ENERGY

Enbridge Income Fund's Green Power electricity generation projects consist of three wind power projects in western Canada, and waste heat recovery facilities that use waste heat from Alliance Canada's compressor stations.

CORPORATE GOVERNANCE

The Administrator and the Trustees of Enbridge Commercial Trust (ECT) are committed to maintaining a high standard of corporate governance for the Fund. They have continued to assess the Fund's governance policies and practices in light of regulatory initiatives in Canada that have been adopted to improve corporate governance, as well as the evolving standards and expectations for governance in the Canadian capital markets. The Administrator is of the view that the Fund's governance structures, systems and practices generally conform with the governance rules and guidelines established by the Canadian Securities Administrators to the extent consistent with the structure of the Fund and ECT and the terms of the Fund Trust Indenture, the ECT Trust Indenture and the other agreements to which the Fund and ECT are parties.

Richard H. Auchinleck

Catherine M. (Kay) Best

J. Richard Bird

J. Lorne Braithwaite

TRUSTEES AND ADMINISTRATORS

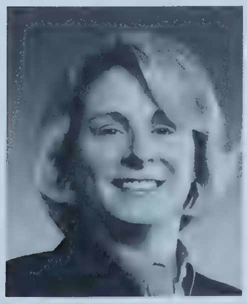
The members of the Board of Trustees of Enbridge Commercial trust, which conducts the affairs of Enbridge Income Fund, are:

Name and Municipality of Residence	Position	Principal Occupation
Richard H. Auchinleck Calgary, Alberta	Trustee	Corporate Director
Catherine M. (Kay) Best Calgary, Alberta	Trustee	Executive Vice President, Risk Management and Chief Financial Officer, Calgary Health Region
J. Richard Bird Calgary, Alberta	Trustee	Executive Vice President, Chief Financial Officer and Corporate Development, Enbridge Inc.
J. Lorne Braithwaite Malahide, County Dublin, Ireland	Trustee	Corporate Director
M. Elizabeth Cannon Calgary, Alberta	Trustee	Dean, Schulich School of Engineering, University of Calgary
David T. Robottom Calgary, Alberta	Trustee	Group Vice President, Corporate Law, Enbridge Inc.
Gordon G. Tallman (Chair) Calgary, Alberta	Trustee	Corporate Director.
Stephen J. Wuori Calgary, Alberta	Trustee	Executive Vice President, Liquids Pipelines, Enbridge Inc.

ADMINISTRATORS

The Administrator of the Enbridge Income Fund and the Manager of ECT is Enbridge Management Service Inc., a wholly-owned subsidiary of Enbridge Inc.

Name and Municipality of Residence	Position with the Manager	Principal Occupation
J. Richard Bird Calgary, Alberta	Director	Executive Vice President, Chief Financial Officer and Corporate Development, Enbridge Inc.
David T. Robottom Calgary, Alberta	Director	Group Vice President, Corporate Law, Enbridge Inc.
Stephen J. Wuori Calgary, Alberta	Director	Executive Vice President, Liquids Pipelines, Enbridge Inc.
James A. Schultz Calgary, Alberta	President	Senior Vice President, New Ventures, Enbridge Inc.
John K. Whelen Calgary, Alberta	Vice President, Business Development & Chief Financial Officer	Senior Vice President, Corporate Development, Enbridge Inc.
David K. Wudrick Calgary, Alberta	Treasurer	Director, Treasury, Enbridge Inc.
Angela J. Bargen Calgary, Alberta	Controller	Director, Financial Reporting, Enbridge Inc.
James E.R. Lord Calgary, Alberta	Corporate Secretary	Senior Legal Counsel, Enbridge Inc.


M. Elizabeth Cannon


David T. Robottom


Gordon G. Tallman


Stephen J. Wuori

MANAGEMENT'S DISCUSSION AND ANALYSIS

CONSOLIDATED RESULTS

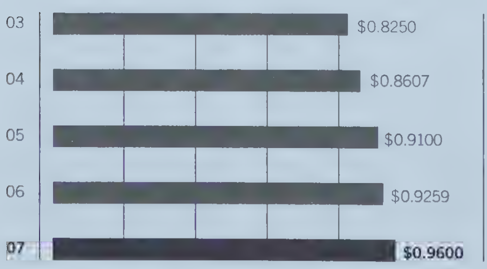
(millions of Canadian dollars except where otherwise noted)

Year ended December 31,	**2007**	2006	2005
Cash Provided by Operating Activities	**80.6**	86.5	84.2
Cash Available for Distribution[1]	**73.5**	74.3	74.3
Cash Distributions Declared	**69.6**	67.3	66.1
Cash Distributions Declared Per Unit *(dollars per unit)*			
Ordinary Units	**0.9600**	0.9259	0.9100
Subordinated Units	**0.9600**	0.9259	0.9100
ECT Preferred Units	**0.9600**	0.9259	0.9100

1 See Non-GAAP Measures. Refer to page 18 for the reconciliation to Cash Provided by Operating Activities.

In 2007, Enbridge Income Fund (the Fund) continued to generate steady and predictable cash distributions while advancing opportunities within its existing businesses. During the year, progress was made on several expansion projects including the BCX receipt expansion project in Alliance Canada, the Westspur expansion on the Saskatchewan System and construction of three waste heat recovery facilities within NRGreen. These initiatives will help to support the Fund's objective of stable and sustainable cash distributions to its Unitholders.

For the year ended December 31, 2007, cash distributions declared of \$69.6 million (2006 – \$67.3 million) represented 94.7% (2006 – 90.6%) of cash available for distribution. As at December 31, 2007, the Fund had distributed 92.1% of cash available since inception. The Fund pays cash distributions on a monthly basis to unitholders of record on the last business day of each month with distributions payable on or about the 15th day of the month following the declaration. Since inception, the Fund has declared the following distributions to ordinary unitholders. Cash distributions of the same amount per unit were also declared on the subordinated units and the ECT preferred units.



Annual Cash Distribution per Unit[1, 2]

1 Distributions include both a return on capital and a return of capital.

2 2003 cash distributions are annualized.

FINANCIAL PERFORMANCE[1]

(millions of Canadian dollars)

Year ended December 31,	**2007**	2006
Alliance Canada	**57.0**	56.3
Saskatchewan System	**13.5**	13.0
Green Power	**2.3**	0.6
Corporate	**(58.3)**	(51.3)
Earnings before the impact of tax changes	**14.5**	18.6
Revalue future taxes due to tax rate changes	**8.5**	16.7
Future taxes due to Tax Fairness Plan	**(1.9)**	–
Earnings	**21.1**	35.3

1 *Financial highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.*

Earnings for the year ended December 31, 2007 decreased by $14.2 million over the prior year due in large part to the revaluation of future taxes, which were more significant in 2006 than 2007 as well as Bill C-52 described below. Earnings before the impact of tax changes were positively impacted by strong results from the Fund's operating segments. However, this increase was more than offset by increased costs in the Corporate segment due primarily to higher interest expense, ECT preferred unit distributions and incentive fees.

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. This change resulted in the recognition of future income tax liabilities and expense of $1.9 million. The impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers in the future. However, as enacted in its present form, the Tax Fairness Plan will, all other things being equal, likely result in a reduction of cash available for distribution by the Fund commencing in 2011. The earnings impact of the legislation was partially offset by 2007 reductions in the federal corporate income tax rate in June of 0.5% and in December of 3.5% effective in 2011. The future tax rate changes substantively enacted in 2006 resulted in a 7% decline in future tax rates and had a more significant impact on earnings than the tax rate changes in 2007.

FORWARD LOOKING INFORMATION

In the interest of providing the Fund's unitholders and potential investors with information about the Fund and its subsidiaries, including management's assessment of the Fund's and its subsidiaries' future plans and operations, certain information provided in this Management's Discussion and Analysis (MD&A) constitutes forward-looking statements or information (collectively, "forward-looking statements"). Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Although the Fund believes that these forward-looking statements are reasonable based on the information available on the date such statements are made, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements.

The Fund's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions and commodity prices, including but not limited to those risks and uncertainties discussed in this MD&A and in the Fund's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Fund's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Fund assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Fund or persons acting on the Fund's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to cash available for distribution and earnings before the impact of tax changes. Cash available for distribution represents cash available to fund distributions on ordinary units, subordinated units and ECT preferred units, as well as for debt repayments and reserves. This measure is important to unitholders as the Fund's objective is to provide a stable and sustainable flow of distributable cash to unitholders. Please refer to the Cash Available for Distribution reconciliation on page 18. Earnings before the impact of tax changes represents earnings adjusted for tax changes enacted in the year. Management believes that the presentation of earnings before the impact of tax changes provides useful information to investors and unitholders as it provides increased predictive value. Cash available for distribution and earnings before the impact of tax changes are not measures that have standardized meanings prescribed by Canadian Generally Accepted Accounting Principles (GAAP) and are not considered GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers.

FUND STRATEGY

FUND'S OBJECTIVE

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. The Fund commenced operations on June 30, 2003 and is administered by Enbridge Management Services Inc. (EMSI or Manager or Administrator), a wholly owned subsidiary of Enbridge Inc. (Enbridge). EMSI also serves as the manager of Enbridge Commercial Trust (ECT), a subsidiary of the Fund. The Fund has investments in businesses that operate crude oil and natural gas pipelines as well as waste heat recovery facilities and wind power.

The Fund's objectives are to provide a stable and sustainable flow of distributable cash and to increase, where prudent, cash distributions on a per trust unit basis.

STRATEGY

In order to further achieve these growth and stability objectives, the Manager pursues a business strategy for the Fund, which involves:

1. maximizing the efficiency and profitability of its existing assets through representation on the Boards and/or management committees governing the Fund's assets;
2. pursuing organic growth and expansion opportunities in its existing businesses; and
3. acquiring and or developing new energy infrastructure businesses that are complementary and in keeping with the risk and return profile of its existing business.

The Tax Fairness Plan as enacted may limit the Fund's ability to successfully execute this strategy and accordingly the Manager is considering a variety of alternatives to optimize returns and value to unitholders.

To successfully pursue this strategy, the Fund must mitigate certain business risks. These risks, and the Fund's strategies for managing them, are described under Risk Factors.

CORE BUSINESS ACTIVITIES

The Fund's activities are carried out through three operating segments:

- Alliance Canada includes the Fund's 50% interest in the Canadian portion of the Alliance System. The Alliance System, comprised of Alliance Canada and Alliance US, transports natural gas from supply areas in Northwestern Alberta and Northeastern British Columbia to delivery points near Chicago, Illinois.
- Saskatchewan System owns and operates crude oil and liquids pipelines systems primarily connecting producing fields in Southern Saskatchewan and Southwestern Manitoba with Enbridge's mainline pipeline, for transportation to the United States.
- Green Power includes entities that produce electricity via alternative energy sources and consists of a 50% interest in each of NRGreen and the SunBridge wind project, as well as a 33% interest in each of the Magrath and Chin Chute wind projects.

SELECTED OPERATING HIGHLIGHTS

Year ended December 31,	**2007**	2006	2005
Average Daily Throughput Volume			
Alliance Canada *(millions of cubic feet per day)*	**1,598.0**	1,592.0	1,597.0
Saskatchewan System[1] *(thousands of barrels per day)*			
Westspur System	**157.2**	155.2	148.7
Saskatchewan Gathering System	**109.6**	103.8	103.2
Weyburn System	**35.0**	37.3	35.0
Virden System	**24.2**	20.7	21.5
Green Power[2] *(thousands of megawatt hours produced)*	**285.0**	52.2	–

1 Totals are not presented as the same volumes can be transported through a combination of the pipelines comprising the Saskatchewan System.
2 Wind assets were acquired on October 1, 2006. NRGreen's Kerrobert waste heat recovery facility began operations on December 29, 2006.

Alliance Canada transportation deliveries for the year, including Authorized Overrun Service (AOS) averaged 1,598 million cubic feet per day (mmcf/d) (20.6% in excess of firm capacity of 1,325 mmcf/d) compared with 1,592 mmcf/d (20.2% in excess of firm capacity) in 2006. This increase is reflective of Alliance Canada's continued focus on improving efficiencies on its system. An increase in AOS does not impact earnings, however, it does increase the competitiveness of Alliance Canada's tolls.

Throughputs for the Saskatchewan System have increased compared with the prior year due to increased volumes trucked to the pipelines as well as additional volumes from new customer connections. Higher throughputs do not directly impact earnings on the Saskatchewan Gathering and Westspur Systems since they are cost of service based. However, they may impact earnings for the Weyburn and Virden Systems.

Megawatt hours produced by Green Power were reflective of a full year of operations from the Wind Power projects and NRGreen.

ALLIANCE CANADA

Alliance Canada consists of approximately 1,560 kilometres of the Alliance System's mainline beginning near Gordondale, Alberta and connecting to Alliance US at the Canada/US border near Carnduff, Saskatchewan. Alliance Canada also includes the Alliance System's lateral pipelines, which connect the mainline to a number of upstream receipt points, primarily at natural gas processing facilities in Northwestern Alberta and Northeastern British Columbia, and related infrastructure.

The Alliance System is designed to transport 1,325 mmcf/d of natural gas from supply areas in Northwestern Alberta and Northeastern British Columbia to delivery points near Chicago, Illinois. Shippers have executed transportation service agreements (TSAs) with each of Alliance Canada and Alliance US, which have an initial 15-year term expiring in November 2015 and provide for 98.5% (2006 – 98.5%) of the Alliance System's available firm transportation capacity. The TSAs are designed to provide Alliance Canada with a steady and predictable cash flow stream through 2015. Additional transportation capacity, AOS, is available to shippers for no additional cost other than the cost of the associated fuel requirements. Beginning in December 2010, each TSA may be renewed on five years notice for successive one-year terms, beyond the initial 15-year term, at the option of the shipper. The remaining 1.5% (20 mmcf/d) of firm capacity was contracted on a short-term basis to March 2010.

Tolls and tariffs for Alliance Canada are regulated by the National Energy Board (NEB). Alliance Canada's TSAs are designed to provide toll revenues sufficient to recover prudently incurred costs of service, including operating and maintenance costs, costs of indebtedness, an allowance for income tax, capital taxes, depreciation and an allowed return on equity based on a deemed 70/30 debt-to-equity ratio. Each shipper's charges are proportionate to the shipper's contracted capacity. Toll adjustments, based on variances between the cost of service forecast used to calculate the toll and the actual cost of service, are made annually. Tolls are submitted to shippers and filed with the regulator for approval.

Depreciation expense on the transmission plant included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts while the depreciation expense in the financial statements is recorded on a straight-line basis of 4% per annum. The negotiated depreciated rates are generally less than the straight-line rates in the earlier years and higher than straight-line depreciation in later years of the shipper transportation agreements. This results in the recognition of a long-term receivable, referred to as deferred transportation revenue, expected to be recovered from shippers in subsequent rates. As at December 31, 2007 $65.6 million (2006 – $47.3 million) was recorded as deferred transportation revenue.

Alliance Canada maintains its productive capacity and ensures the future sustainability of its distributions through its maintenance program. The program includes semi-annual inspections of all compressor stations as well as internal corrosion coupon inspections and annual Pipe-to-Soil surveys, atmospheric inspections, above ground indirect assessments and the repair and replacement of compressor parts. Mainline pipeline inspection is completed with a seven year re-occurring schedule. Other maintenance performed includes soil resistance surveys, and corrosion deficiency reports. Maintenance expenditures may vary from year to year.

EARNINGS

(millions of Canadian dollars)

Year ended December 31,	2007	2006
Earnings before the impact of tax changes	57.0	56.3
Revalue future taxes due to tax rate changes	2.0	2.7
Earnings	59.0	59.0

Earnings for the year ended December 31, 2007 were comparable the year ended December 31, 2006. In both years, substantial future tax rate reductions were enacted, which resulted in future tax recoveries and increased earnings for the period. Future taxes in Alliance Canada result from differences, which arose on the acquisition of Alliance Canada from Enbridge, between the accounting values and the tax bases of certain assets and liabilities. Excluding the future tax impacts on earnings, earnings increased due to a higher allowance for income tax reflected in tolls due to increased taxable income. Higher taxable income resulted from lower capital cost allowance claims and a decrease in a deductible repair and maintenance expenditures for 2007. Earnings were also positively impacted by a reduction in the capital tax rate, which decreased the tax incurred by the Fund related to its investment in Alliance Canada. These factors were partially offset by the reduction in the equity return caused by the depreciating investment base.

Earnings reflect a return on equity applied to investment base accounts, as well as an allowance for deemed income and provincial capital taxes on regulated activities. The rate used to calculate the equity return is not expected to change; however, related annual earnings will decline over time as the investment base is depreciated.

Revenue primarily reflects the cost of service recovery, whereby an increase in costs increases revenue. Revenues for the year ended December 31, 2007 were $209.1 million compared with $201.4 million for the year ended December 31, 2006. This increase was driven primarily by higher cost of service recoveries primarily related to property taxes. In 2006, Alliance Canada received a large property tax credit that resulted in lower cost of service recoveries reflected in revenue. This credit did not impact earnings since it was also reflected in the operating costs for Alliance Canada.

STRATEGY

Alliance Canada manages its operating assets and infrastructure with the objective of maximizing shipping capacity, excelling in operating performance and increasing the competitiveness of its tolls. Looking to the future, Alliance Canada is focused on pipeline optimization, expansion opportunities and other development initiatives with an aim of increasing the competitiveness of its tolls and demand for services to ensure steady and sustainable cashflow.

Asset Optimization Projects

In order to maximize AOS levels and minimize fuel usage, Alliance is continuing to focus on strategies that will enhance the performance of its mainline compressor units primarily through increasing the longevity and efficiency of its units through cost-effective equipment upgrades. Alliance Canada recognizes that fuel gas is an increasingly important component of the unit cost of transportation.

Enhancement of Existing Compressor Units

In 2007, Alliance Canada initiated a Product Improvement Program (PIP) for its LM2500+ units at the Windfall and Morinville compressor stations. These two sites are the first stations on the mainline

delivery System and are the only sites that have the LM2500+ units installed to which this upgrade program is applicable.

PIP is expected to extend the maintenance interval to 50,000 hours from the current 25,000 hour requirement as well as yield annual fuel savings for the shippers' benefit. Alliance Canada has achieved the expected operating performance improvements associated with the program including meeting required emissions levels with the new combustor design.

Alliance Canada has completed PIP upgrades to two of the three LM2500+ gas turbines (the unit) at the Windfall compressor site. An Environmental Kit Upgrade (EKU) was also installed with one of upgraded Windfall units. An additional EKU will be installed in April 2008 for the other upgraded Windfall unit. The third unit at Windfall has been upgraded to a G4 system, more fully described in the following section.

The Morinville compressor site upgrade with the new PIP and the EKU hardware was completed in September 2007. This upgrade utilized the unit from the Windfall compressor site that was replaced as a result of the G4 project. The unit that came out of Morinville will be upgraded with the new PIP and EKU hardware and then will become a spare unit. From a logistical standpoint, this spare arrangement will improve flexibility over the current situation in which Alliance Canada draws from a vendor's equipment lease pool.

The total installed cost for the program for Alliance Canada is forecasted to be $9.8 million.

New Gas Generator and Power Turbine

A LM2500+ G4 version gas generator and power turbine was installed during the second quarter of 2007 at Windfall replacing one of the three existing gas generators and power turbines in Windfall. This project is expected to decrease ongoing maintenance and turn-around costs. The operating performance for this latest-generation G4 unit is meeting all expectations for power and heat rate.

The capital cost for this program for Alliance Canada was just under the budgeted amount of $8.4 million.

Alameda Cooler Project

Alliance Canada has installed additional aerial cooler facilities at the Alameda compressor station in Saskatchewan. Aerial coolers remove heat developed by the compression of natural gas by transferring the heat to the ambient air. Cooling increases the density of natural gas, thereby improving hydraulic characteristics. This in turn gives rise to reduced fuel consumption at stations downstream of Alameda. The NEB approved this project in May 2007, civil construction activities commenced in June and mechanical construction activities started in July. In November 2007 the installation of the new coolers at the Alameda compressor station was completed. The total cost of this enhancement project for Alliance Canada was slightly below the expected cost of $8.0 million.

BCX Expansion Project

Alliance Canada is constructing an expansion project in British Columbia (BCX) that will enhance its capacity for natural gas receipts originating in northeastern British Columbia. The BCX project involves construction of a Taylor Junction compression station that would enable increased receipt capacity on the Taylor-Aitken Creek lateral system. This project will not increase the mainline capacity but will enable existing shippers to increase gas nominations at receipt points in B.C.

In September 2007, the NEB approved the application for the BCX project. However, in October, the Canadian Association of Petroleum Producers (CAPP) filed an application for review and stay with the NEB as well as a motion for leave to appeal the NEB's decision with the Federal Court of Appeal. Alliance Canada successfully opposed CAPP's motion and applications at the Federal Court of Appeal and with the NEB. In November, the Federal Court of Appeal denied CAPP's motion and on January 10, 2008, the NEB denied CAPP's application for review. In view of the denial, a decision regarding the stay application was not necessary.

Construction of this project can now proceed and is expected to commence in early 2008 with an expected in-service date in late 2008. Field survey activities were undertaken in October 2007. The total estimated cost to Alliance Canada is $30.3 million.

2008 Toll Filing

On October 31, 2007, following consultation with its shippers, Alliance Canada filed its 2008 tolls with the NEB. Alliance Canada's 2008 tolls will increase 10.7% effective January 1, 2008, from $0.776/mcf to $0.859/mcf. This increase is due to higher operating costs, a scheduled increase in the negotiated depreciation rate for 2008 and higher property and income taxes. The increase in operating costs is primarily due to including compressor overhaul maintenance and other replacement equipment in operating costs for 2008. This is a change from prior year toll filings where the overhaul program and equipment replacement costs were included in property additions. Other increases in operating costs included in the 2008 toll filing reflect increased pipeline integrity costs and the expenses associated with the implementation of a new SAP information system. These increases are partially offset by reduced interest expense and return on equity due to a declining investment base. On December 12, 2007, a shipper on the Alliance system filed an objection to the tolls with the NEB and requested either the tolls not be approved or be approved on an interim refundable basis pending a hearing and final decision. On December 19, 2007, the NEB responded to Alliance's application and the shipper's objection by placing Alliance's proposed 2008 tolls on an interim refundable basis, effective January 1, 2008, until a final decision can be made by the NEB. The NEB also requested comments from interested parties on Alliance's 2008 tolls application. Two shippers and CAPP have filed letters with the Board. One shipper and CAPP stated they did not object to the 2008 tolls. The other shipper stated that it supported the 2008 tolls. The Partnership does not anticipate that the NEB review will have a material impact on the Partnership's operations or financial position.

CALPINE ENERGY SERVICES CANADA PARTNERSHIP *(CESCA)* CLAIM SETTLEMENT

In 2006, CESCA, a shipper on the Alliance System accounting for 1.5% of firm capacity, repudiated its firm transportation service agreement with Alliance Canada. Alliance Canada immediately arranged for the placement of this capacity and drew on CESCA's letter of credit for funds equal to twelve months of demand charges in respect of CESCA's former transportation capacity. The funds were deposited into an account held in trust with Alliance Canada's Security Trustee to be applied against any shortfall in tolls arising from the new placement. Transportation revenue for 2007 was unaffected by this repudiation due to the re-marketing of the transportation capacity and use of the funds received as security.

In 2006, Alliance Canada and Alliance US filed proofs of claim in the Calpine Corporation Chapter 11 Bankruptcy proceeding. These claims were in respect of guarantees provided by Calpine Corporation as security for the performance of CESCA's obligations under its transportation contracts. In 2007, an agreement with CESCA and related Calpine entities was reached, which provided Alliance Canada and Alliance US with one general unsecured claim against CESCA. On January 16, 2008, full payment for settlement of the two claims totaling $20.7 million was received.

CAPITAL EXPENDITURES

Capital expenditures in 2007, representing the Fund's 50% interest, were $17.9 million (2006 – $10.5 million) including $9.1 million (2006 – $7.6 million) in maintenance capital expenditures and $8.8 million (2006 – $2.9 million) in enhancement capital. Maintenance expenditures were lower than the expected $11.3 million due to the timing of compression overhauls and the deferral of Alliance Canada's Grand Prairie office expansion. Enhancement expenditures were $2.4 million greater than expected due primarily to the BCX project as well as several asset optimization projects, specifically the Alameda Cooler project, which will increase efficiency on the Alliance System and provide for cost savings in the future. Expenditures in 2007 were focused on compressor overhauls, asset optimization projects, and pipeline and information system maintenance programs aimed to improve system efficiency, as well as the BCX project.

In 2008, Alliance Canada expects to spend approximately $13.5 million, representing the Fund's 50% interest, primarily on the BCX project. Alliance Canada will continue to perform compressor overhauls in 2008 to continue to improve system efficiency. Starting January 1, 2008, all major maintenance expenditures including compressor overhauls will be expensed.

BUSINESS RISKS

The risks identified below are specific to Alliance Canada. General risks that affect the Fund as a whole are described under Risk Factors.

Re-Contracting Risk

The revenue generated by Alliance Canada is derived from tolls that are based on the TSAs which, unless renewed, will terminate at the end of the primary term in November 2015. Beyond the primary term, the decision by shippers to renew will depend on numerous factors, including the level of demand for natural gas in the geographic areas which can be served by pipelines and distribution facilities connected to the Alliance System, the ability and willingness of shippers to meet such demand, the competitiveness of Alliance Canada's toll structure and general market conditions. If shippers do not renew their TSAs, Alliance Canada may be forced to lower its tolls to avoid losing shippers, thereby reducing Alliance Canada's cash flow from the TSAs.

Recovery of Capital

When the primary term of the TSAs expires, Alliance Canada is expected to have recovered approximately 54% of the capital cost of the Alliance Canada pipeline through depreciation charges collected from shippers. Since there is no guarantee that all shippers will extend their contracts beyond the primary term, the undepreciated capital cost may not be recovered as soon as expected. In order to mitigate the risk of non-renewal, there are financial incentives for shippers to renew their contracts beyond the primary term. Additionally, Alliance Canada continues to focus on ensuring the competitiveness of its tolls and providing a high level of service through system enhancements.

Competition

The Alliance System faces competition in pipeline transportation from both existing and proposed projects. Any new or upgraded pipelines could provide shippers and competing pipelines greater access to natural gas markets or offer more desirable natural gas transportation services due to location, facilities or other factors. Further, these pipelines could charge tolls or provide service to locations that result in greater net profit for shippers. As a result, Alliance Canada may be forced to lower its transportation tolls upon the expiration of the primary term of the TSAs. Alliance Canada mitigates this risk through its continued focus on strong shipper relations and competitive tolls as well as its AOS which allows shippers access to transportation capacity at no additional cost.

Exposure to Shippers

Alliance Canada is highly dependent on shippers for revenues from contracted capacity on the Alliance Canada system. Failure of the shippers to fulfill their contractual obligations under the TSAs could have an adverse effect on the cash flows and financial condition of Alliance Canada and could impair the ability of Alliance Canada to meet its debt obligations and make distributions to its limited partners. A prolonged economic downturn in the energy industry, significant reductions in the supply of natural gas in the Western Canadian Sedimentary Basin, competition from alternative sources of natural gas supply and from other providers of natural gas transportation services, and the price of and demand for natural gas and natural gas transportation services in markets served by Alliance Canada, among other things, could impact the ability of some or all of the shippers to fulfill their obligations under the TSAs.

Recovery of Costs

Pursuant to the terms of the TSAs and in accordance with the negotiated toll principles accepted by the NEB, Alliance Canada is permitted to recover from the shippers costs incurred in the construction and operation of the Alliance System that are actually and reasonably incurred. There can be no certainty that all costs incurred by Alliance Canada will be recoverable through the transportation tolls. Since transportation tolls are set in advance based on forecast expenses, and adjusted periodically to reflect actual expenses, there is no assurance that the variances in the estimate will be recovered from shippers in subsequent periods.

Credit Risk

Currently, approximately 9.0% of firm capacity on Alliance Canada's system is contracted to shippers who do not have an investment grade rating or equivalent strong credit status and are required to post security. These shippers have provided security to Alliance Canada; however, the security does not fully cover more than one year's demand charges under the TSAs. There can be no assurance that the security will be adequate to compensate Alliance Canada if a shipper is unable to fulfill its obligations under its TSA.

Dependence on Interconnected Systems and Facilities

The Alliance System operates as an integrated pipeline; therefore, any matters which limit or restrict the ability of Alliance US to operate will equally affect the ability of Alliance Canada to operate. Alliance Canada may have no control over matters which may adversely affect Alliance US. In addition, the debt obligations of Alliance Canada and Alliance US are cross-collateralized. In the event of a default of the debt obligations of either Alliance Canada or Alliance US, the assets of the non-defaulting entity may be used to satisfy the debts of the defaulting entity. The debt obligations of both Alliance Canada and Alliance US also contain default provisions related to the occurrence of certain bankruptcy, insolvency or other adverse events affecting Aux Sable Extraction LP, where those events would have a material adverse effect on Alliance.

There is a significant degree of dependency on Aux Sable Liquid Products LP (Aux Sable), a related party to Alliance Canada through common ownership interest, to satisfy its requirements to provide heat content management services to Alliance US. Should Aux Sable fail to provide heat content management services for any reason, Alliance Canada may experience operational issues, including an interruption or curtailment of transportation service on the Alliance System. It is not possible to predict the extent or duration of these operational problems or their precise financial or operational effect on Alliance Canada.

SASKATCHEWAN SYSTEM

The Saskatchewan System transports crude oil from producing fields in Southern Saskatchewan and Southwestern Manitoba as well as natural gas liquids from the Steelman gas processing plant to Cromer, Manitoba where the liquids enter Enbridge's mainline pipeline to be transported to the United States.

The Saskatchewan System is comprised of the Saskatchewan Gathering, Westspur, Weyburn and Virden pipeline systems. Collectively referred to as the Saskatchewan System, these crude oil and liquids pipeline systems comprise approximately 296 kilometres of trunk line, 1,900 kilometres of gathering pipeline and related terminals and tankage facilities. The capacity of each of the Saskatchewan Gathering and the Westspur Systems is 190,000 barrels per day (bpd) and the capacity of the Weyburn and Virden Systems is 47,000 bpd and 37,000 bpd, respectively.

The Saskatchewan Gathering System and the Westspur System are regulated by Saskatchewan Energy and Resources (SER) and the NEB, respectively. Both systems follow the principles for establishing tolls outlined in agreements with shippers, signed in 1985, expired in 1995, and now monitored on a customer complaint basis. The Saskatchewan Gathering System and the Westspur System tolling agreements are based on a cost of service methodology and are designed to provide toll revenues sufficient to recover operating costs, depreciation, deemed interest expense, income tax and to provide an administrative expense allowance as well as a return on rate base. This methodology increases the stability and predictability of cash flows generated by these systems.

The Weyburn and Virden Systems are regulated by the SER and Manitoba Science, Technology, Energy and Mines (STEM), respectively. Rates are established based on historical precedence, signed agreements, or both, with customers and are updated to reflect changing market conditions when warranted.

The SER and the NEB exercise statutory authority over various matters such as construction and operations, and may exercise authority over rates and ratemaking agreements with customers and underlying accounting principles. The regulators do not regularly review or approve the rates established by the pipeline systems comprising the Saskatchewan System. However, in the event of a customer complaint, the regulator would review and provide a ruling on the rates in question. There have been no customer toll complaints filed to date for any of the systems comprising the Saskatchewan System.

The Saskatchewan System maintenance program maintains its productive capacity and includes sump tanks, berm and line repairs, piping modifications, and tank and meter repairs. Maintenance expenditures will vary year to year as some maintenance is performed on a cyclical basis. For example, software upgrades are scheduled every five years. Tank repairs occur annually; although, the extent of repairs will fluctuate each year based on the age and size of the tank. The program also includes annual system integrity programs which consist of cathodic protection, inline inspections, station integrity, tank integrity, as well as chemical injections, which serve as corrosion inhibitors, into the lines.

EARNINGS

(millions of Canadian dollars)

Year ended December 31,	**2007**	2006
Earnings before the impact of tax changes	**13.5**	13.0
Revalue future taxes due to tax rate changes	**5.8**	14.0
Earnings	**19.3**	27.0

Earnings for the year ended December 31, 2007 of $19.3 million were lower than the prior year primarily due to significant future tax rate reductions in the second quarter of 2006. Future taxes in the Saskatchewan System result from temporary differences between the accounting value of the property, plant and equipment and the tax basis. Earnings before the impact of tax changes were positively impacted by two factors. Higher throughputs on the Virden system resulted in higher tariff revenue and earnings in the year. Additionally, the Saskatchewan System benefited from the impact of higher oil prices on its allowance oil gains on the Weyburn and Virden systems.

Earnings from both the Saskatchewan Gathering System and the Westspur System reflect an equity return on rate base. The rate used to calculate the equity return is not expected to change; however, the rate base will change due to depreciation over time as well as maintenance and enhancement capital additions. Earnings from both the Weyburn System and the Virden System reflect toll revenues less costs incurred.

Revenue for the year ended December 31, 2007 was $54.4 million compared with $51.7 million in the prior year period. This $2.7 million increase was primarily reflective of greater cost of service recoveries on the Saskatchewan Gathering and Westspur Systems including higher operating expenses driven by an increase in labour costs, as well as increased throughputs on Weyburn and Virden. Revenue for the Saskatchewan Gathering and Westspur Systems primarily reflect the cost of service recovery, whereby an increase in costs result in increased revenue.

STRATEGY

The Saskatchewan System operates its pipelines and supporting assets with the objective of providing reliable, cost effective transportation solutions and generating strong cashflows. The Saskatchewan System is focused on meeting the increased crude oil production and growing demand for pipeline capacity in the areas served by its systems through expansion and development initiatives, specifically the Westspur expansion. This growth is expected to increase distributable cash flow from this segment in the near term. Transportation by pipeline is generally more cost effective than other alternatives and as a result, the Saskatchewan System is currently expanding its capacity by approximately 20% to meet the growing demand for its services.

Westspur Expansion

In November 2007, construction began on the Westspur expansion, which will increase capacity on the Westspur System between Midale and Steelman by approximately 20,000 bpd and between Alida and Cromer by approximately 77,000 bpd. This expansion is expected to be in service by the second quarter of 2008 at a total cost of approximately $30.5 million.

CAPITAL EXPENDITURES

Capital expenditures in 2007 were $21.1 million (2006 – $12.2 million) including $4.4 million (2006 – $3.5 million) in maintenance capital and $16.7 million (2006 – $8.7 million) in enhancement capital. Expenditures were lower when compared to the expected expenditures of $35.8 million in 2007. The $14.7 million decrease was due to delays in construction of the Westspur expansion. Expenditures in 2007 were focused on sustaining capital infrastructure, the completion of new customer connections, pipeline integrity, tank repairs and the expansion of the Westspur and Weyburn Systems.

The Saskatchewan System anticipates capital expenditures of approximately $36.0 million in 2008. Of this amount, approximately $6.3 million is allocated to maintenance capital expenditures, including the annual repair and inspection programs involving electronic pipe corrosion inspection tools, or

"smart pigs". The remaining $29.7 million is for enhancement capital including the capacity expansion on the Westspur System.

BUSINESS RISKS

The risks identified below are specific to the Saskatchewan System. General risks that affect the Fund as a whole are described under Risk Factors.

Competition

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers with the effect of forcing the Saskatchewan System to lower its transportation rates to avoid losing shippers, thereby reducing cash flow. The Saskatchewan System manages exposure to shippers and competition by ensuring the shipping rates are competitive and by providing a high level of service. Further, the Saskatchewan System's right-of-way and expansion efforts have served to provide this segment with a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies and its expansion projects in order to meet its shippers' growing demand.

Demand for Services

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are based on expired agreements with certain crude oil shippers and are monitored on a customer complaint basis. The majority of the volumes shipped on these systems are transported on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

Credit Risk

The Saskatchewan System's trade receivables consist primarily of amounts due from companies operating in the oil and gas exploration and development industry. The credit risk associated with these receivables is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements.

GREEN POWER

WIND POWER

Green Power includes the Fund's interest in three wind power projects including a 50% interest in the SunBridge project at Gull Lake, Saskatchewan and a 33% interest in each of the Magrath and Chin Chute projects in Southern Alberta. Collectively referred to as Wind Power, the SunBridge, Magrath and Chin Chute wind power projects have a combined capacity of 71 megawatts (MW). SunBridge consists of 17 turbines, each with a capacity of 0.66 MW for an 11 MW total. The power from Sunbridge is delivered into the Saskatchewan power grid and is sold to Saskatchewan Power Corporation (SaskPower) under a long term Power Purchase Agreement (PPA) which expires in 2022. The Magrath and Chin Chute wind projects both consist of 20 turbines, each with capacity of 1.5 MW for a 30MW total. The energy produced at Magrath and Chin Chute is delivered into the Alberta power grid. The Fund has entered into long-term agreements to fix the price received for its portion of production on these projects. The Magrath contract expires on November 30, 2024 while the Chin Chute contract expires on December 31, 2017.

The Fund entered into a contract to sell all available emission reduction credits generated by the Fund's interest in the Chin Chute and Magrath projects to Enbridge. The contract has an initial 20-year term ending October 1, 2026 and provides for a fixed price of $5 per tonne of avoided CO_2 emissions, based

based on a negotiated rate of converting megawatts generated to tonnes of emissions reduced, plus applicable taxes.

To reduce the uncertainty associated with government support programs, Enbridge agreed to pay the Fund \$10 per megawatt hour (MWh) of power produced by the Fund's interest in Chin Chute until the Wind Power Production Incentive (WPPI) or similar successor program funding was reinstated. The EcoEnergy Renewable Power Program Incentive (ERPPI) funding, a successor program to WPPI, was approved for Chin Chute on November 27, 2007 by Natural Resources Canada and is retroactive to April 1, 2007.

The Wind Power assets are subject to semi-annual maintenance to maintain the life of the turbines. Future maintenance expenditures will vary each year and given the infancy of this industry, long term projections of maintenance capital expenditures will likely differ from the actual results.

NRGREEN

NRGreen began operations of its non-regulated waste heat recovery facility at Kerrobert, Saskatchewan on December 29, 2006 and is constructing three additional facilities in Loreburn, Estlin and Alameda, Saskatchewan. Electricity is generated by harnessing the waste heat produced by Alliance Canada's gas turbines at its compressor stations and converting it to electrical energy. SaskPower purchases the power generated from the 5.0 MW Kerrobert facility under a 10-year PPA that expires on December 29, 2016. NRGreen may elect to issue two successive renewal notices, each extending the PPA for an additional five-year period. In addition, on August 22, 2006, NRGreen signed PPAs with SaskPower for the future power generated by NRGreen's three additional waste heat recovery facilities currently under construction upon commencement of operations, which is expected in mid-2008.

NRGreen maintenance is performed concurrently with the Alliance Canada semi-annual inspection of the Kerrobert compressor station.

EARNINGS

(millions of Canadian dollars)

Year ended December 31,	**2007**	2006
Earnings before the impact of tax changes	**2.3**	0.6
Revalue future taxes due to tax rate changes	**0.1**	–
Future taxes due to Tax Fairness Plan	**0.2**	–
Earnings	**2.6**	0.6

Earnings for the year ended December 31, 2007 were positively impacted by the future tax rate reduction in the fourth quarter of 2007 as well as the Tax Fairness Plan, which effectively changed the future tax rate from 0% to 29.5% starting in 2011. Future tax recoveries in the Green Power segment arose from differences between the accounting value and the fair value of the property, plant and equipment on the acquisition of the Wind Power projects.

Excluding the impact of tax changes, earnings were reflective of strong wind resource in the first and fourth quarter, offset by operational issues in the fourth quarter at NRGreen's Kerrobert facility. The Kerrobert facility experienced a mechanical seal failure on its gas turbine, which resulted in shut down of production for 47 days. The facility was re-started in November and NRGreen is pursuing the recovery of repair costs and lost revenue through warranty claims and/or from its insurers.

STRATEGY

The objective of Green Power is to produce reliable, cost effective electricity via alternative energy sources to ensure stable, relatively predictable cash flow streams for the Fund. Power production by the Green Power segment is supported by long-term PPAs and power swap agreements which serve to mitigate the risk of fluctuating power prices and to stabilize cash flows.

In 2008, Green Power will focus on completing construction of the three new waste heat facilities which are expected to commence operations mid-2008. The Fund's 50% share of the remaining cost of these projects in 2008 is expected to be $4.8 million, which will be funded through the credit facility.

CAPITAL EXPENDITURES

Capital expenditures in 2007 were $17.2 million (2006 – $10.1 million) compared with an expected $20.5 million. The difference was due to delays in construction of the Alameda, Estlin and Loreburn waste heat facilities. Commissioning of the Loreburn and Estlin facilities was completed in the fourth quarter of 2007. Green Power anticipates capital expenditures of approximately $5.3 million in 2008 focused primarily on the completion of the three new waste heat facilities.

BUSINESS RISKS

The risks identified below are specific to the Green Power segment. General risks that affect the Fund as a whole are described under Risk Factors.

Variable Wind Resource

The generation of electricity associated with the Fund's interest in Wind Power is dependent on the wind resource at each location. Although extensive long-term wind studies have been conducted, there is no assurance the wind resource and thus electricity generation at each location will meet expectations.

Dependence

The NRGreen waste heat recovery facilities generate electricity from the waste heat emitted from Alliance Canada's compressor stations. As a result, any shutdowns for maintenance or reduction in activity at these compressor stations will have a negative impact on the level of production for NRGreen.

Counterparty Risk

The primary source of fixed price revenue for each wind project and for NRGreen is a single counterparty. The stability of the Fund's revenue and cash flows from this segment is dependent upon the ability of these counterparties to pay their monthly charges. If these counterparties are unable to fulfill their obligations under their purchase agreements and an alternate counterparty is not available, Wind Power would be exposed to variable power prices. This risk is mitigated by investment grade requirements of the counterparties involved.

CORPORATE

The Corporate segment includes management and administrative costs, corporate financing costs, distributions to ECT preferred unitholders, business development activities not attributable to a specific business segment and other corporate costs including current and future income taxes.

(millions of Canadian dollars)

Year ended December 31,	**2007**	2006
Costs before the impact of tax changes	**(58.3)**	(51.3)
Revalue future taxes due to tax rate changes	**0.6**	–
Future taxes due to Tax Fairness Plan	**(2.1)**	–
Total costs	**(59.8)**	(51.3)

Corporate costs before the impact of tax changes were $58.3 million for the year ended December 31, 2007 compared with $51.3 million for the year ended December 31, 2006. The $7.0 million increase was driven by several factors including higher income taxes. Interest expense increased as a result of the increased borrowings used to finance the acquisition of the Wind Power projects in October 2006 as well as other expansion projects. Additionally, both incentive fees and ECT preferred unit distributions increased due to a 4.5% increase in per unit distributions for all Fund units commencing in the fourth quarter of 2006.

SENSITIVITY ANALYSIS

Fluctuations in interest rates impact the interest expense incurred on the Fund's credit facility. A 0.5% increase in the interest rate on the Fund's credit facility would decrease earnings by $0.6 million. Alliance Canada is not sensitive to fluctuations in interest rate under its cost of service toll methodology.

LIQUIDITY AND CAPITAL RESOURCES

Cash generated by operating activities, supplemented by additional borrowings as necessary, is expected to be sufficient to meet the forecast liquidity and capital resource requirements of the Fund. Forecasted liquidity requirements include monthly cash distributions to unitholders, including ordinary and subordinated unitholders of the Fund as well as preferred unitholders of ECT.

The Fund's current liabilities routinely exceed current assets. Current liabilities include current maturities of long-term debt, which are typically refinanced with long-term debt. Excluding current maturities of long-term debt, the Fund does not have a working capital deficit. The Fund's cash balance at December 31, 2007 of $14.7 million includes $2.4 million held in trust in Alliance Canada, pursuant to finance agreements within Alliance Canada.

In July 2007, Alliance Canada acquired a $12.4 million investment in asset-backed commercial paper, issued by a structured investment trust (the Trust). The investment is held in trust with Alliance Canada's Security Trustee as part of Alliance Canada's current debt service requirement. As a result of deteriorating liquidity in the asset-backed commercial paper market in mid 2007, the Trust was unable to redeem this investment upon its maturity on August 31, 2007. Pursuant to a restructuring plan, conversion of the commercial paper into long-term notes is expected to occur in the first quarter of 2008.

The Fund does not anticipate that the treatment of Alliance Canada's investment in asset-backed commercial paper will have any significant impact on its operations or ability to meet upcoming debt obligations.

OPERATING ACTIVITIES

Cash provided by operating activities was $80.6 million for the year ended December 31, 2007, compared with $86.5 million in the prior year. The decrease reflected changes in working capital and lower earnings from operations.

INVESTING ACTIVITIES

Cash used for investing activities for the year ended December 31, 2007 was $71.2 million, a decrease of $8.3 million from the prior year. The decrease reflected the acquisition of the Wind Power projects in 2006.

Capital expenditures are categorized as either maintenance or enhancement. Maintenance capital expenditures are determined based on the capital requirements necessary to maintain the service capability of the existing assets and include the replacement of system components and equipment that are worn, obsolete or completing their useful life. Enhancement expenditures include capital expansion projects and other projects that improve the service capability of existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, or enable the Fund to respond to governmental regulations and developing industry standards. Maintenance capital expenditures are funded through cash from operations, whereas enhancement capital expenditures are funded through debt and, as required, the issuance of equity.

FINANCING ACTIVITIES

Financing activities for the year ended December 31, 2007 related to monthly distributions to ordinary and subordinated unitholders as well as changes in outstanding indebtedness under the credit facility and non-recourse debt funding for Alliance Canada.

In June 2007, Alliance Canada amended the maturity date of its existing credit facility from 2011 to 2012. In September 2007, the Fund increased its available credit under its existing unsecured credit facility from $105.0 million to $150.0 million under the same terms and conditions. The Fund's credit facility matures in 2010. The additional available credit will support the Fund's current expansion initiatives. The credit facility may be used to provide working capital to the Fund, to finance acquisitions and development projects or for general purposes. At December 31, 2007, the Fund had $51.3 million (2006 – $35.1 million) in undrawn credit facilities for liquidity requirements.

Payments due for contractual obligations for each of the next five years and thereafter are as follows:

(millions of Canadian dollars)	Total	Less than 1 year	2 years	3 years	4 years	5 years	After 6 years
Long-Term Debt	1,039.2	28.7	130.9	132.4	36.3	81.9	629.0
Operating Leases	36.0	3.1	2.9	3.2	3.2	2.8	20.8
Other Long-Term Obligations	8.1	8.1	–	–	–	–	–
	1,083.3	39.9	133.8	135.6	39.5	84.7	649.8

CASH AVAILABLE FOR DISTRIBUTION[1]

(millions of Canadian dollars)

Year ended December 31,	2007	2006
Cash Provided by Operating Activities	**80.6**	86.5
Add/(Deduct):		
ECT preferred unit distributions[2]	**36.5**	35.2
Alliance Canada maintenance capital expenditures[3]	**(9.1)**	(7.6)
Alliance Canada debt repayments[4]	**(26.1)**	(27.9)
Alliance Canada cash retained	**(12.3)**	(8.1)
Green Power cash retained	**(0.2)**	(4.0)
Saskatchewan System maintenance capital expenditures[3]	**(4.4)**	(3.5)
Change in operating assets and liabilities in the period[5]	**8.5**	3.7
Cash Available for Distribution	**73.5**	74.3
Cash Available for Distribution is comprised of the following:		
Alliance Canada distributions	**66.9**	66.6
Alliance Canada capital tax	**(0.5)**	(1.0)
Saskatchewan System operating income before depreciation and amortization	**27.0**	26.0
Saskatchewan System maintenance capital expenditures	**(4.4)**	(3.5)
Green Power distributions	**4.2**	1.1
Corporate management and administrative expense	**(4.8)**	(4.3)
Corporate interest expense	**(13.2)**	(10.3)
Corporate other income	**0.2**	0.1
Corporate current taxes	**(1.9)**	(0.4)
Cash Available for Distribution	**73.5**	74.3
ECT Preferred Unit Distributions Declared	**36.5**	35.2
Ordinary and Subordinated Units Distributions Declared	**33.1**	32.1
Cash Distributions Declared	**69.6**	67.3

1 *See Non-GAAP Measures on page 3.*
2 *The cash available for distribution above is compared to the total distributions, including the ECT preferred unit distributions. Since the ECT preferred units are treated as debt under GAAP with distributions deducted from earnings, the ECT preferred unit distributions have been added back to the cash provided from operating activities.*
3 *Maintenance capital expenditures reduce the cash available for distribution since these expenditures are funded through cash from operations.*
4 *Debt repayments in Alliance Canada are deducted from cash from operations in deriving the cash available for distribution because they are funded from cash from Alliance Canada's operations.*
5 *Change in operating assets and liabilities in the period reflect changes in non-cash working capital related to operating activities. The change has been added back to cash available for distribution since fluctuations in working capital are expected each period and are not indicative of changes in cash available to be distributed.*

The above calculations of cash available for distribution represent cash available to fund distributions on ordinary units, subordinated units and ECT preferred units, as well as for debt repayments and reserves.

The cash retained by Alliance Canada and Green Power reflects the cash from operations of these segments that has not been distributed to the Fund. While the cash from operations was proportionately consolidated and was included in the results of the Fund, it is not available for distribution by the Fund until it has been received from Alliance Canada and the Green Power segment. Cash retained by Alliance Canada and Green Power includes debt service reserves, capital expenditures and other cash needed to fund working capital or other requirements of these segments.

Distributions from Alliance Canada, which are subject to the approval of the Board of Directors of the General Partner of Alliance Canada, are made on a quarterly basis and paid in the month subsequent to quarter end. In the Green Power segment, distributions represent the monthly cash distributions from the Wind Power projects and the quarterly distributions from NRGreen as well as cash settlements paid or received by the Fund for the wind power purchase swap agreements. Distributions from NRGreen are paid in the month subsequent to quarter end.

In 2007, Alliance Canada returned $1.0 million to the Fund representing a return of contributed surplus from construction accounts. This receipt has been excluded from the cash available for distribution reconciliation since it relates to enhancement capital. Enhancement capital is funded via debt and equity; therefore, cash received related to enhancement capital is reserved for debt repayments.

The following table provides a comparison of cash distributions to cash provided by operating activities and to earnings.

(millions of Canadian dollars)

Year ended December 31,	**2007**	2006
Cash Provided by Operating Activities	**80.6**	86.5
Earnings	**21.1**	35.3
Ordinary and Subordinated Unit Cash Distributions Declared[1]	**33.1**	32.1
Excess of cash provided by operating activities over ordinary and subordinated cash distributions declared	**47.5**	54.4
Excess/(Shortfall) of earnings over ordinary and subordinated cash distributions	**(12.0)**	3.2

1 ECT Preferred Unit Distributions have been excluded from this reconciliation since these distributions are reductions to earnings under GAAP.

For the year ended December 31, 2007, cash flows provided by operating activities in the period exceeded cash distributions paid to ordinary and subordinated unitholders by $47.5 million (2006 – $54.4 million.) This excess represented cash reserved for working capital requirements and maintenance capital expenditures, as well as cash retained by joint ventures.

Earnings were $12.0 million lower than cash distributions to ordinary and subordinated unitholders for the year ended December 31, 2007 while earnings exceeded distributions by $3.2 million in prior year. An excess of distributions over earnings is expected to continue in the future and partly represents a return of capital to unitholders (including ECT Preferred Unitholders.) Under GAAP, earnings reflect non-cash items such as amortization of deferred financing costs and depreciation as well as changes in future income taxes due to tax rate changes, all of which do not impact cash flow. Depreciation does not necessarily represent the cost of maintaining productive capacity; therefore, cash required for maintenance may be lower than depreciation expense. In 2006, the excess of earnings over cash distributions reflected non-cash future income tax recoveries of $16.7 million as a result of the significant reduction in future income tax rates.

The Fund's policy is to distribute, on average over a five year rolling period, 95% of cash available for distribution. The remaining 5% is used by the Fund to repay debt obligations, for general purposes and to levelize distributions. The current level of distributions may change based on the performance of the Fund's businesses, the level of continued investment, the Fund's ability to obtain financing and the impacts of the Tax Fairness Plan. The Board of Trustees periodically approves changes to distributions based on cash flow to meet the Fund's distribution policy. Overall, cash distributions of the Fund are governed by the Trust Indenture, which requires a distribution of all distributable cash flow.

Distributable cash flow is defined to generally mean cash from operating, investing and financing activities, less certain items, including any cash withheld as a reserve that the Manager determines to be necessary or appropriate for the proper management of the Fund and its assets.

TAXATION OF DISTRIBUTIONS

Under Canadian tax laws, a component of the Fund's cash distributions are taxable in the hands of the unitholder, with the remaining portion treated as a return of capital unless held in a tax-deferred account. Based on current operations, the Fund estimates that approximately 80% of cash to be distributed in 2007 and to be distributed 2008 will be included in the income of unitholders for tax purposes. The remaining 20% of cash distributed represents the non-taxable return of capital.

TAX TREATMENT OF UNITHOLDER DISTRIBUTIONS

Based on the Fund's analysis and external advice, the Fund believes the income portion of distributions to individuals holding their units outside a tax deferred account will be treated the same as taxable dividends from a Canadian corporation commencing in 2011. Returns of capital by the Fund to its unitholders should not be impacted by the Tax Fairness Plan. Since this is only a general summary and unitholders' individual circumstances will vary, it is not intended, nor should it be treated, as a representation of the income tax consequences to any particular unitholder or as tax or legal advice. Unitholders should consult their own tax advisors to clarify the impact of the Tax Fairness Plan on their individual circumstances.

SUSTAINABILITY OF DISTRIBUTIONS AND PRODUCTIVE CAPACITY

Although the Fund intends to continue to make cash distributions from funds generated by its operating segments, the distributions are not guaranteed. The sustainability of the Fund's distributions is a function of several factors: the demand for the services provided by its businesses, maintenance of the productive capacity of its assets, and its ability to comply with covenants in its debt agreements as well as repay or refinance its debt as it comes due.

Demand for the Fund's services could be affected by a variety of factors including supply of and demand for the underlying commodities transported on the pipelines owned by the Fund and the supply of and demand for power generated by facilities within the Green Power segment. The Fund and each of its segments have implemented strategies to sustain and increase the demand for their respective services.

Each operating segment maintains its productive capacity and ensures the future sustainability of its distributions through maintenance programs which include annual maintenance expenditures as well as major maintenance capital expenditures. Maintenance expenditures are funded through cash from operations. Refer to the Capital Expenditures sections in this MD&A for further discussion on planned maintenance and enhancement capital activities for 2008.

The sustainability of the Fund's distributions and productive capacity is also a function of its ability to meet its debt obligations and to economically obtain financing to fund growth and operational requirements. In 2007, the Fund increased the size of its standby revolving credit facility without changes to the facility's terms and conditions, demonstrating the Fund's continued ability to debt finance.

The Tax Fairness Plan, as enacted in its present form, will also impact future distributions. Under the enacted legislation, a distribution tax of 29.5% will begin in 2011 and, all other things being equal, likely result in a reduction of cash available for distribution by the Fund commencing in 2011.

RISK FACTORS

The Fund's business activities are subject to execution, market price, credit and operating risks. The Fund has formal risk management policies and risk management systems designed to mitigate these risks.

TAX FAIRNESS PLAN

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, achieved Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. This change resulted in the recognition of future income tax liabilities and expense of $1.9 million. Future income tax expense was not recorded for the temporary differences attributed to Alliance Canada because rate regulated accounting allows for the taxes payable method when future income taxes are expected to be included in the rates charged to customers in the future and fully recovered.

The Fund, with input from external legal and financial advisors, is carefully assessing the impact of the legislation on the business and financial outlook of the Fund and its broader effect on the income trust sector as a whole. The Fund's objective in carrying out these activities is to adopt a strategy that will maximize value to unitholders going forward.

On December 20, 2007 the Minister of Finance announced proposed technical amendments to further clarify the Tax Fairness legislation contained in Bill C-52. The announcement provides clarity to the existing Tax Fairness legislation. If the proposed technical amendments are enacted as announced, Alliance Canada will continue to be a non-taxable entity for federal and provincial income tax purposes.

As enacted in its present form, the Tax Fairness Plan will result in a distribution tax of 29.5% starting in 2011 and, all other things being equal, likely result in a reduction of cash available for distribution by the Fund commencing in 2011. With respect to the limitations on equity unit issuances, the Manager believes the Fund should be able to fund its currently identified growth plans. However, with the current uncertainty in the capital markets resulting from Bill C-52, there can be no assurance that sufficient capital will be available to fund further acquisitions or expansion projects.

REGULATION AND LEGISLATION

Earnings and expansion projects on the Alliance Canada and the Saskatchewan Systems are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of the expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays.

Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of Alliance Canada and the Saskatchewan System. Further, the nature and degree of regulation and legislation affecting energy companies in Canada has changed significantly in past years and there is no assurance that further substantial changes will not occur. Such regulations and legislation may adversely affect the toll structure or other aspects of the Fund's business or the operations and creditworthiness of shippers.

FINANCING CAPACITY AND LIQUIDITY

The Fund's financing risk relates to the price volatility and availability of debt and equity in the market to finance expansion projects. This risk is directly influenced by the enactment of the Tax Fairness Plan

which limits the amount of equity that can be issued by the Fund as well as market factors, financial performance and by the Fund's current credit rating.

The Fund continuously monitors its capital requirement and debt levels in order to ensure sufficient liquidity and capital resources. Currently, the Fund estimates that its credit facility, combined with cash generated by operating activities, is sufficient to meet the forecast liquidity and capital resource requirements of the Fund.

DEBT COVENANTS

Both the Fund's credit facility and the Alliance Canada credit facility include provisions that prohibit distributions in the event of default. The Fund's credit facility agreement includes a covenant that limits unconsolidated indebtedness to 4 times earnings before interest, taxes, depreciation and amortization (EBITDA.) In the event of default and in the absence of a waiver from the lenders, failure to remediate this covenant could result in a reduction of distributions to unitholders. Under the Alliance Canada credit facility, distributions cannot be made to owners if Alliance Canada's debt service coverage ratio, calculated as of the applicable distribution date, falls below 1.25 to 1 for the four preceding fiscal quarters and the four succeeding fiscal quarters. The Fund and Alliance Canada actively monitor debt covenants to ensure compliance. As at December 31, 2007, both companies were in full compliance with the debt covenants and expect to continue to be in compliance for the foreseeable future. Additionally, the Fund's obligations to pay the principal, interest and all other amounts payable by the Fund under its medium term notes outstanding rank in priority to distributions.

INTEREST RATE RISK

The Fund is exposed to interest rate fluctuations on variable rate debt and on future debt issuances. Increases in interest rates could reduce the Fund's competitiveness and could have a material adverse effect on the Fund's cash flow and distributable cash. The Fund may use derivative financial instruments in order to manage interest rate risk. There are no interest rate derivative financial instruments outstanding at year-end.

SUPPLY AND DEMAND

The operation of the Fund's liquids and natural gas pipelines is dependent upon the supply of and demand for crude oil and natural gas from Western Canada and demand for crude oil from the refiners in the Mid-western United States. The demand for crude oil by refiners is dependent upon a number of factors including the price of crude oil, the cost of operating the refinery and market prices for the various refined products. Supply is dependent upon a number of variables, including:

- the level of exploration, drilling, reserves, and production of crude oil and natural gas;
- the accessibility of Western Canadian crude oil and natural gas;
- the price and quality of crude oil and natural gas available from alternative Canadian and United States sources; and
- the regulatory environments in Canada and the United States, including the continued willingness of the governments of both countries to permit the export of crude oil and natural gas from Canada to the United States on a commercially acceptable basis.

OPERATING RISK

The operation of Alliance Canada, the Saskatchewan System and Green Power involve many operating risks, including the failure of equipment, information systems or processes, poor performance of equipment (whether due to misuse, unexpected degradation or design, construction or manufacturing defects), lack of spare parts, operator error, labour disputes, disputes or issues with interconnected

facilities and carriers and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the respective systems. The occurrence or continuance of any of these events could increase the cost of operating Alliance Canada, the Saskatchewan System and/or Green Power and reduce transportation capacity, thereby potentially impacting cash flow. The Fund employs various inspection and monitoring methods to manage pipeline, turbine and facility integrity as well as to minimize system disruptions.

Environmental Costs and Liabilities

The operation of the Saskatchewan System and Alliance Canada are subject to federal, provincial and local laws and regulations relating to environmental protection and operational safety. Risks of substantial environmental costs and liabilities, including those from leaks and explosions, are inherent in pipeline operations and there can be no assurance that significant costs and liabilities, including those relating to claims for damages to property and persons resulting from operations of Alliance Canada and/or the Saskatchewan System, will not be incurred. To mitigate this risk, Alliance Canada and the Saskatchewan System have established safety and environmental policies that are designed to ensure that all aspects of their operations comply with existing regulations relating to personal safety and protection of the environment. It is not possible to predict the effect that any future changes in environmental laws and regulations will have on future earnings and there can be no assurance that environmental costs incurred by Alliance Canada or the Saskatchewan System will be partially or fully recoverable under their tolls.

Easement Rights

Alliance Canada, Saskatchewan System and Green Power have acquired easement rights from landowners, tenants and service lease owners in order to construct, install and operate their pipeline and wind turbines. These easement rights were obtained through voluntary negotiation and, in certain cases, through statutory rights of entry. There can be no assurance that legal challenges will not be brought forward with respect to the form, content, or recording of such easements, or to business segments' compliance with the terms of such easements during the construction and operation of the pipeline or wind turbine.

MATERIAL DEBT

The Fund has debt instruments with maturities ranging from 2009 to 2014. If, on maturity, refinancing of the debt is not possible, or if the terms of the replacement debt are less favourable than the existing terms, cash available for distribution and earnings could decrease. In addition, Alliance Canada has debt instruments outstanding with maturities ranging from 2012 to 2025. Similarly, if such debt is refinanced on less favourable terms or cannot be refinanced, distributions from Alliance Canada will likely decrease.

FLUCTUATIONS IN DISTRIBUTIONS

Although the Fund's policy is to distribute on average, 95% of cash available for distribution, cash distributions are not guaranteed and distributions will fluctuate. The actual amount of distributable cash will depend on numerous factors, including operating cash flow, demand for services, general and administrative costs, applicable taxes, debt service costs, capital expenditures, restrictions imposed by lenders, and disruptions in service and reserves established by the Fund, and ECT.

CRITICAL ACCOUNTING ESTIMATES

REGULATORY ASSETS AND LIABILITIES

Alliance Canada and the Saskatchewan System are subject to regulation by the NEB, SER and STEM. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non rate-regulated entities. The Fund also records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. As of December 31, 2007, the Fund's regulatory assets totalled $65.6 million (2006 – $48.0 million). To the extent that the regulator's actions differ from the Fund's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

DEPRECIATION

Depreciation of property, plant and equipment, the Fund's largest asset with a net book value at December 31, 2007 of $1,329.0 million, or 71.5% of total assets, is generally provided on either a straight-line basis over the estimated service lives of the assets or a unit of throughput basis commencing when the asset is placed in service. When it is determined that the estimated service life of an asset does not reflect the expected remaining period of benefit, prospective changes are made to the estimated service life. In general, estimates of service lives are based on third party engineering studies, experience and industry practice. There are a number of assumptions inherent in estimating the service lives of the Fund's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Fund's pipelines as well as the demand for crude oil and natural gas and the integrity of the Fund's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Fund's operating segments. Revised assumptions have historically resulted in extending useful lives.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The present value of expected future cash flows is determined using assumptions such as the probability of abandonment in place versus removal and the estimated costs required upon abandonment in each case, the discount rate and the estimated time to abandonment.

The undiscounted amount of expected cash flows required to settle the AROs is estimated at $43.5 million (2006 – $43.5 million) with the majority estimated to be settled beginning in the year 2033. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 6.58%.

A legal obligation exists for costs associated with retirement of the Alliance Canada pipeline; however, a provision for AROs has not been recognized as it is not possible to make a reasonable estimate of the AROs due to the indeterminate timing, the long lived nature of the assets and the scope of the asset retirements. The Fund's estimates of retirement costs and the timing of settlement of these costs could change as a result of changes in timing and cost estimates as well as changes in regulatory requirements.

CHANGE IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Fund adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", Section 3861 "Financial Instruments – Disclosure and Presentation" and Section 3865 "Hedges". In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated.

The adoption of the new standards did not impact the Fund's earnings or cash flows.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the valuation of the Fund's financial instruments has not changed. The methods by which the Fund determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Comprehensive Income and Equity

The new standards introduce comprehensive income, which consists of earnings and Other Comprehensive Income (OCI). The Fund's consolidated financial statements include a Statement of Comprehensive Income, which principally includes the components of comprehensive income. The Fund's OCI is currently comprised of the effective portion of changes in unrealized gains and losses related to cash flow hedges.

The Fund now presents a Consolidated Statement of Unitholders' Equity, which includes the change for each component of unitholders' equity. The cumulative changes in OCI are recorded in Accumulated Other Comprehensive Income (AOCI), a separate component of unitholders' equity. The components of AOCI are reflected in the Consolidated Statement of Comprehensive Income.

Unrealized gains and losses included in AOCI are reclassified to earnings when they become realized in accordance with hedge accounting standards.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of Canadian dollars) Increase/(Decrease)	Assets	Liabilities and Equity
Deferred Amounts and Other Assets[1]	(10.1)	–
Accounts Payable and Accrued Liabilities[2]	–	1.0
Long-Term Debt[1]	–	(5.4)
Non-Recourse Long-Term Debt[1]	–	(4.7)
Long-Term Liabilities[2]	–	5.1
Accumulated Other Comprehensive Loss[2]	–	(6.1)
	(10.1)	(10.1)

1 *On January 1, 2007, the Fund reclassified unamortized deferred financing fees of $10.1 million from deferred amounts and other assets to long-term debt and non-recourse long-term debt.*

2 *As a result of the new standards for derivative instruments, on January 1, 2007, the Fund recognized a liability of $6.1 million for unrealized losses related to its power purchase swap agreements designated as cash flow hedges.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosure and Presentation

Effective January 1, 2008, the Fund will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosure and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Fund will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Fund manages as capital, whether the Fund has complied with any externally imposed capital requirements and, if the Fund has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861, Financial Instruments – Disclosure and Presentation. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand discussion around the significance of financial instruments for the Fund's financial position and performance; and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

FINANCIAL INSTRUMENTS

Information about the financial instruments outstanding at year end including the fair values, notional or principal amounts and maturities are shown in Note 16 of the Fund's consolidated financial statements for the year ended December 31, 2007.

DISCLOSURE CONTROLS AND PROCEDURES

Based on the requirements of Multilateral Instrument 52-109 of the Canadian Securities Administrators, EMSI, the Administrator of the Fund, under the supervision of the President and Chief Financial Officer of the Administrator, evaluated the effectiveness of the Fund's disclosure controls and procedures (as defined in Multilateral Instrument 52-109). Based on that evaluation, EMSI concluded that the Fund's disclosure controls and procedures were effective as of December 31, 2007.

SELECTED ANNUAL FINANCIAL INFORMATION[1]

(millions of Canadian dollars, except where otherwise noted)	**2007**	2006	2005
Revenues	**270.8**	254.4	249.0
Earnings	**21.1**	35.3	15.2
Per Unit *(dollars per unit)*	**0.61**	1.02	0.44
Total Assets	**1,858.8**	1,867.3	1,844.1
Total Long Term Liabilities	**1,508.6**	1,509.1	1,490.0

1 *Selected Quarterly Financial Information has been extracted from financial statements prepared in accordance with GAAP.*

Significant items that have impacted annual financial information are as follows:

- 2007 earnings included future income tax recoveries of $6.6 million for future tax rate changes enacted during the year.
- 2007 revenues reflected higher cost of service recovered through tolls as well as a full year of operations from the Green Power segment.
- 2006 revenues reflected higher cost of service recovered through tolls.
- 2006 earnings included future income tax recoveries of $16.7 million for future tax rate changes enacted in the year.
- Total assets and liabilities in 2006 reflected the Wind Power project acquisition.

SELECTED QUARTERLY FINANCIAL INFORMATION[1]

	2007				2006			
(millions of Canadian dollars, except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**73.0**	65.0	67.8	65.0	68.2	60.8	63.5	61.9
Earnings	**10.8**	3.8	3.0	3.5	3.2	5.8	21.0	5.3
Earnings Per Unit (basic and diluted)	**0.31**	0.11	0.09	0.10	0.09	0.17	0.61	0.15
Cash Distributions Declared[2]	**17.3**	17.4	17.4	17.4	17.2	16.7	16.7	16.7

1 *Selected Quarterly Financial Information has been extracted from financial statements prepared in accordance with GAAP.*
2 *Cash distributions declared on ordinary and subordinated units and ECT preferred units.*

Starting in the fourth quarter of 2006, revenue includes amounts for electricity generated in the Green Power segment, which varies with fluctuations in weather. Typically, revenue peaks in the winter months during the first quarter and, to a lesser extent, in the fourth quarter of the year when wind volumes are higher.

Significant items that have impacted quarterly financial information are as follows:

- Fourth quarter earnings in 2007 reflected future income tax recoveries of $7.6 million due to the substantive enactment of reductions in future tax rates during the quarter.
- Second quarter earnings in 2007 reflected future income tax expense of $1.9 million due to the substantive enactment of the Tax Fairness Plan.
- Second quarter earnings in 2006 reflected future income tax recoveries of $16.7 million due to the substantive enactment of reductions in future tax rates during the quarter.
- The Board of Trustees approved increases in distributions of 1% and 4.5%, on the Fund's ordinary and subordinated units and the ECT preferred units, effective with the distributions payable to holders of record on January 31, 2006 and November 30, 2006, respectively.

FOURTH QUARTER 2007 HIGHLIGHTS

Fourth quarter earnings for 2007 were $10.8 million, or $0.31 per unit, compared with $3.2 million, or $0.09 per unit, in 2006. The increase reflected future income tax recoveries totalling $7.6 million recognized in the quarter as a result of the 3.5% reduction in future tax rates enacted in December 2007.

SUPPLEMENTARY INFORMATION

OUTSTANDING UNIT DATA

	Number of Units Outstanding
Ordinary Units	20,125,000
Subordinated Units	14,500,000
ECT Preferred Units	38,023,750

Outstanding unit data information is provided as at February 4, 2008.

RELATED PARTY TRANSACTIONS

Information about the Fund's related party transactions is included in Note 19 to the Fund's consolidated financial statements for the year ended December 31, 2007.

Additional information relating to the Fund is available on www.sedar.com.

Dated February 4, 2008

MANAGEMENT'S REPORT

TO THE UNITHOLDERS OF ENBRIDGE INCOME FUND

The management of Enbridge Management Services Inc. is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

To meet its responsibility for reliable and accurate financial statements, management has established or assumed responsibility for monitoring systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable, and accurate, and that assets are safeguarded from loss or unauthorized use and transactions are executed in accordance with management's authorization. The internal control system includes an internal audit function as well as monitoring of an established code of business conduct.

The Board of Trustees and the Audit Committee are responsible for all aspects related to governance of the Fund. The Audit Committee, composed of independent and financially literate directors, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Audit Committee meets regularly during the year with management, internal auditors and independent auditors to review the consolidated financial statements, Management's Discussion and Analysis, and Annual Information Form as well as internal controls related thereto, prior to submission to the Board of Trustees for approval.

PricewaterhouseCoopers LLP, appointed by the unitholders as the Fund's independent auditors, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

J A Schultz

James A. Schultz
President

John K Whelen

John K. Whelen
Vice President, Business Development &
Chief Financial Officer

February 4, 2008

AUDITORS' REPORT

TO THE UNITHOLDERS OF ENBRIDGE INCOME FUND

We have audited the consolidated balance sheet of Enbridge Income Fund (the "Fund") as at December 31, 2007 and 2006 and the consolidated statements of earnings, comprehensive income, unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Income Fund as at December 31, 2007 and 2006 and the results of its operations and its cashflows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 4, 2008

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of dollars, except per unit amounts)

Year ended December 31,	**2007**	2006
Revenues	**270.8**	254.4
Expenses		
Operating and maintenance	**73.2**	61.8
Management and administrative	**4.8**	4.3
Depreciation and amortization	**81.8**	78.5
	159.8	144.6
	111.0	109.8
Other Income and Expense	**1.2**	1.0
Interest Expense *(Note 12)*	**(61.8)**	(60.1)
ECT Preferred Unit Distributions *(Note 13)*	**(36.5)**	(35.2)
	13.9	15.5
Income Tax Recovery *(Note 17)*	**7.2**	19.8
Earnings	**21.1**	35.3
Basic and Diluted Earnings per Trust Unit *(Note 15)*	**0.61**	1.02

The accompanying notes to the consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

(millions of dollars)

Year ended December 31,	**2007**	2006
Trust Units	**333.4**	333.4
Deficit at Beginning of Year	**(36.1)**	(39.3)
Earnings	**21.1**	35.3
Ordinary and subordinated trust unit distributions	**(33.1)**	(32.1)
Deficit at End of Year	**(48.1)**	(36.1)
Accumulated Other Comprehensive Loss at Beginning of Year	**–**	–
Cumulative impact of change in accounting policy *(Note 3)*	**(6.1)**	–
Other comprehensive loss	**(0.1)**	–
Accumulated Other Comprehensive Loss at End of Year	**(6.2)**	–
Total Unitholders' Equity	**279.1**	297.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of dollars)

Year ended December 31,	**2007**	2006
Earnings	**21.1**	35.3
Other Comprehensive Income/(Loss)		
Change in unrealized fair value on cash flow hedges, net of tax	**(0.4)**	–
Reclassification of realized losses on cash flow hedges to earnings	**0.3**	–
	(0.1)	–
Comprehensive Income	**21.0**	35.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of dollars) Year ended December 31,	**2007**	2006
Cash Provided by Operating Activities		
Earnings	**21.1**	35.3
Charges/(credits) not affecting cash		
Depreciation and amortization	**81.8**	78.5
Amortization of deferred financing charges	**1.6**	1.8
Amortization of fair value increment on debt	**(5.1)**	(5.2)
Future income taxes	**(9.1)**	(20.2)
Other	**(1.2)**	–
Changes in operating assets and liabilities		
Change in accounts receivable and other	**(5.3)**	6.6
Change in accounts payable and accrued liabilities	**16.5**	7.0
Change in deferred amounts and other assets	**(19.0)**	(20.9)
Change in long-term liabilities	**(0.7)**	3.6
	80.6	86.5
Investing Activities		
Acquisition of wind assets *(Note 6)*	**–**	(42.1)
Additions to property, plant and equipment	**(55.4)**	(32.8)
Change in construction payable	**(9.6)**	(4.6)
Investment in asset backed commercial paper *(Note 7)*	**(6.2)**	–
	(71.2)	(79.5)
Financing Activities		
Net change in long-term credit facility	**29.5**	58.0
Net change in non-recourse long-term credit facility	**17.6**	1.3
Repayment of non-recourse long-term debt	**(26.1)**	(27.9)
Ordinary and subordinated trust unit distributions *(Note 15)*	**(33.1)**	(32.1)
	(12.1)	(0.7)
(Decrease)/Increase in Cash and Cash Equivalents	**(2.7)**	6.3
Cash and Cash Equivalents at Beginning of Year	**17.4**	11.1
Cash and Cash Equivalents at End of Year	**14.7**	17.4
Cash and Cash Equivalents	**12.3**	13.4
Cash and Cash Equivalents in Trust	**2.4**	4.0
	14.7	17.4

The accompanying notes to the consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of dollars) December 31,	**2007**	2006
ASSETS		
Current Assets		
Cash and cash equivalents	**14.7**	17.4
Accounts receivable and other	**32.8**	27.5
	47.5	44.9
Property, Plant and Equipment *(Note 8)*	**1,329.0**	1,349.0
Intangible Assets *(Note 9)*	**96.4**	101.9
Goodwill	**308.1**	308.1
Deferred Amounts and Other Assets *(Note 7)*	**75.0**	60.3
Future Income Taxes *(Note 17)*	**2.8**	3.1
	1,858.8	1,867.3
LIABILITIES AND UNITHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**39.6**	32.0
Distributions payable	**2.8**	2.8
Current portion of non-recourse long-term debt *(Note 11)*	**28.7**	26.1
	71.1	60.9
Long-Term Debt *(Note 10)*	**284.2**	259.0
Non-Recourse Long-Term Debt *(Note 11)*	**761.1**	781.3
ECT Preferred Units *(Note 13)*	**380.2**	380.2
Long-Term Liabilities	**11.0**	4.8
Asset Retirement Obligations *(Note 14)*	**7.9**	7.9
Future Income Taxes *(Note 17)*	**64.2**	75.9
	1,579.7	1,570.0
Unitholders' Equity		
Trust units *(Note 15)*	**333.4**	333.4
Deficit	**(48.1)**	(36.1)
Accumulated other comprehensive loss	**(6.2)**	–
	279.1	297.3
	1,858.8	1,867.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Approved by the Trustees of Enbridge Commercial Trust on behalf of Enbridge Income Fund:

CM Best

Catherine M. Best
Trustee

R Auchinleck

Richard H. Auchinleck
Trustee

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE AND DESCRIPTION OF THE FUND

Enbridge Income Fund (the Fund) is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. The Fund commenced operations on June 30, 2003. Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of Enbridge Inc. (Enbridge), administers the Fund. EMSI also serves as the manager of Enbridge Commercial Trust (ECT), a subsidiary of the Fund.

The Fund conducts its business through three operating segments: Alliance Canada, Saskatchewan System and Green Power. These segments are strategic business units established along service lines by management to assess operational performance and to achieve the Fund's long-term goals.

ALLIANCE CANADA

Alliance Canada consists of the Fund's 50% interest in the Canadian portion of the 3,000 kilometre (km) Alliance System. The Alliance System, comprised of Alliance Canada and Alliance US, transports natural gas from supply areas in Northwestern Alberta and Northeastern British Columbia to delivery points near Chicago, Illinois. The Canadian portion includes approximately 1,560 km of the Alliance System's high-pressure, natural gas transmission system as well as its lateral pipeline system, which connects the mainline to a number of upstream receipt points, and related infrastructure.

SASKATCHEWAN SYSTEM

The Saskatchewan System includes four crude oil and liquids pipeline systems: Saskatchewan Gathering, Westspur, Weyburn, and Virden pipeline systems. Together these systems include approximately 296 km of trunk line and 1,900 km of gathering pipeline with capacities ranging from 37,000 barrels of oil per day (bpd) to 190,000 bpd.

GREEN POWER

Green Power includes the Fund's 33% to 50% interests in three wind power projects in Saskatchewan and Southern Alberta. Collectively, these wind power projects can generate a total of 71 megawatts (MW) of electricity. Green Power also includes the Fund's 50% interest in NRGreen, which develops and operates waste heat recovery power generation facilities primarily in Saskatchewan along the Alliance Pipeline. These facilities convert waste heat to electricity, which is then sold under long-term power purchase agreements.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Fund have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise noted. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the financial statements. Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Fund and its subsidiaries as well as its proportionate share of the accounts of its joint ventures.

REGULATION

Both Alliance Canada and the systems comprising the Saskatchewan System are subject to regulation by various authorities, including the National Energy Board (NEB), Saskatchewan Energy Resources (SER) and Manitoba Science, Technology, Energy and Mines (STEM). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. In order to recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers through rates. In the absence of rate regulation, the Fund would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded

in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Regulatory liabilities are recorded in Accounts Payable and Accrued Liabilities.

Allowance for Funds Used During Construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Fund would capitalize only the interest component. Therefore, the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized by the Fund.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in income but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed. Delivery or service performance only takes place when there is a sales contract in place specifying delivery volumes or services required and sales prices. Customer credit worthiness is assessed before contracts are signed. However, certain operations are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts, resulting in the recognition of regulatory assets and liabilities.

The Saskatchewan Gathering and Westspur systems within the Saskatchewan System as well as Alliance Canada generate revenues under the cost of service model. As a result, revenues include amounts related to expenses recognized in the financial statements that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to regulatory receivable or payable balances.

FINANCIAL INSTRUMENTS

The Fund classifies financial assets as either held for trading, held to maturity, loans and receivables or available for sale. The Fund classifies financial liabilities as either held for trading or other financial liabilities.

Financial assets and liabilities that are "held for trading" are measured at fair value with changes in fair value recognized in earnings, except for derivatives that are designated as, and determined to be, effective hedging instruments, whose fair value is recorded in Other Comprehensive Income (OCI).

Financial assets that are "available for sale" are measured at fair value with changes in those fair values recorded in OCI. Financial assets that are "held to maturity" and "loans and receivables" and financial liabilities that are "other financial liabilities" are measured at amortized cost using the effective interest rate method of amortization.

Cash and cash equivalents are designated as "held for trading" and are measured at carrying value which approximates fair value due to the short-term nature of these instruments. Accounts receivable and other is designated as "loans and receivables". Accounts payable and other, distributions payable, long-term debt, non-recourse long-term debt and ECT Preferred Units are designated as "other financial liabilities".

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Fund incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

Hedges

From time to time, the Fund uses derivatives and non-derivative financial instruments to manage changes in commodity prices and interest rates. Hedge accounting is optional and it requires the Fund to document the hedging relationship and to test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the

underlying hedged item on an ongoing basis. The Fund presents the earnings and cash flow effects of hedging items with the hedged transaction.

Cash Flow Hedges

The Fund uses cash flow hedges to manage changes in power prices and interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings with the hedged item.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period they occur with the hedged item.

The Fund does not use derivative instruments for speculative purposes. However, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as a hedging item, changes in the fair value are recorded in current period earnings.

INCOME TAXES

Pursuant to the *Income Tax Act* (Canada) as presently enacted, the Fund and ECT, as trusts, are not subject to income taxes to the extent that income and taxable capital gains are paid or payable to unitholders. In addition, each of the Fund and ECT are contractually committed to distribute to unitholders all or virtually all taxable income and taxable capital gains. However, certain subsidiary corporations are taxable and applicable income and capital taxes have been reflected in these consolidated financial statements.

For non-regulated operations, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated operations of the Fund recover tax expense based on the taxes payable method when prescribed by regulators or in ratemaking agreements that are subject to regulatory approval. Therefore, rates do not include the recovery of future income taxes related to temporary differences and the Fund does not record future income tax assets or liabilities related to these differences. The Fund expects that all future income taxes will be recovered in rates when they become payable.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents are recorded at fair value and include short-term deposits with terms to maturity of three months or less when purchased.

PROPERTY, PLANT AND EQUIPMENT

Enhancement capital expenditures, including upgrades and expansions, and maintenance capital expenditures, including major renewals and improvements, are capitalized at cost with depreciation commencing when the asset is placed in service. Maintenance and repair costs are expensed as incurred.

Depreciation of property, plant and equipment is generally provided on a straight-line basis over the estimated service life of the assets commencing when the asset is placed in service. Depreciation of pipeline in service in the Saskatchewan System is determined based on unit of throughput. Line fill is not depreciated.

INTANGIBLE ASSETS

Intangible assets consist of acquired long-term transportation service agreements (TSAs) with shippers on Alliance Canada and the production incentive agreements for the Magrath and Chin Chute wind power projects. Intangible assets are amortized on a straight-line basis over the expected life of the agreements.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually and written down to fair value if impairment occurs.

DEFERRED AMOUNTS

Deferred amounts and other assets include costs which regulatory authorities have permitted or are expected to permit to be recovered through future rates.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Fund's estimates of retirement costs could change as a result of changes in timing and cost estimates as well as changes in regulatory requirements.

Although a legal obligation exists for costs associated with retirement of the Alliance Canada pipeline, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

3. CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Fund adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", Section 3861 "Financial Instruments – Disclosure and Presentation" and Section 3865 "Hedges". In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated.

The adoption of the new standards did not impact the Fund's earnings or cash flows.

Comprehensive Income and Equity

The new standards introduce comprehensive income, which consists of earnings and OCI. The Fund's consolidated financial statements now include a Statement of Comprehensive Income. The Fund's OCI is currently comprised of the effective portion of changes in unrealized gains and losses related to cash flow hedges.

The Fund now presents a Consolidated Statement of Unitholders' Equity, which includes the change for each component of unitholders' equity. The cumulative changes in OCI are recorded in AOCI, a separate component of unitholders' equity. The components of AOCI are reflected in the Consolidated Statement of Comprehensive Income.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the valuation of the Fund's financial instruments has not changed. The methods by which the Fund determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars)

Increase/(Decrease)	Assets	Liabilities and Equity
Deferred Amounts and Other Assets [1]	(10.1)	–
Accounts Payable and Accrued Liabilities [2]	–	1.0
Long-Term Debt [1]	–	(5.4)
Non-Recourse Long-Term Debt [1]	–	(4.7)
Long-Term Liabilities [2]	–	5.1
Accumulated Other Comprehensive Loss [2]	–	(6.1)
	(10.1)	(10.1)

1 *The Fund reclassified unamortized deferred financing fees of $10.1 million from deferred amounts and other assets to long-term debt and non-recourse long-term debt.*

2 *The Fund recognized a liability of $6.1 million for unrealized losses related to its power purchase swap agreements designated as cash flow hedges.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosure and Presentation

Effective January 1, 2008, the Fund will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosure and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Fund will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Fund manages as capital, whether the Fund has complied with any externally imposed capital requirements and, if the Fund has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861, Financial Instruments – Disclosure and Presentation. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand disclosure about the significance of financial instruments for the Fund's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

Accounting for the Effects of Rate Regulation

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to Rate Regulated Operations. The AcSB decided to retain much of the existing guidance related to rate-regulated operations however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465, *Income Taxes*, and the exemption from CICA Handbook Section 1100, *Generally Accepted Accounting Principles,* will be removed, effective January 1, 2009. The Fund will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

Alliance Canada

The NEB approves the cost of service toll methodology for the Alliance pipeline, which was negotiated between Alliance Canada and its contracted shippers. Toll adjustments are filed annually with the regulator. The tolls include a return on equity component of 11.26% (2006 – 11.25%) after tax and are based on a deemed 70% debt and 30% equity structure.

Saskatchewan System

The Saskatchewan Gathering System and the Westspur System are regulated by SER and the NEB, respectively. Both systems follow the cost of service methodology. Tolls are subject to change from time to time based on the differences between the estimated cost of service and actual costs incurred and earn a 6.5% return on a semi-depreciated rate base.

The regulators do not regularly review or approve the rates established by the pipeline systems comprising the Saskatchewan System. However, in the event of a customer complaint, the regulator would review and provide a ruling on the rates in question.

REGULATORY RISK AND UNCERTAINTIES AFFECTING RECOVERY OR SETTLEMENT

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Fund's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated entities has resulted in recording the following regulatory assets and liabilities:

(millions of dollars) December 31,	**2007**	2006	Estimated Settlement Period (years)	Earnings Impact[1] **2007**	Earnings Impact[1] 2006
REGULATORY ASSETS/(LIABILITIES)					
Alliance Canada					
Deferred transportation revenue[2]	**65.6**	47.3	18	**18.3**	17.3
Transportation revenue adjustment[3]	**–**	(0.8)	1	**0.8**	3.0
Saskatchewan System					
Transportation revenue adjustment[3]	**(0.6)**	0.7	1	**(1.3)**	1.1

1 *Represents the effect of rate regulation on after tax reported earnings.*

2 *Deferred transportation revenue is related to the cumulative difference between GAAP depreciation expense included in the financial statements of Alliance Canada and depreciation expense included in transportation tolls. Alliance Canada expects to recover this difference over a number of years when depreciation rates in the TSAs are expected to exceed the GAAP depreciation rates, beginning in 2011 and ending in 2025. This regulatory asset is not included in the rate base.*

3 *The transportation revenue adjustment is the cumulative difference between actual expenses and estimated expenses included in transportation tolls. For Alliance Canada, the transportation revenue adjustment is recoverable/(refundable) under the TSAs with shippers and the Saskatchewan Gathering and Westspur Systems expect to recover/(refund) the difference in the following year through tolls. The transportation revenue adjustments are not included in the rate base*

OTHER ITEMS AFFECTED BY RATE REGULATION

Future Income Taxes

In the absence of rate regulation, future income taxes liabilities of $64.6 million (2006 – $77.4 million) associated with certain assets, primarily property, plant and equipment, would be recorded.

Accumulated unrecorded future income tax liabilities of $16.7 million (2006 – $13.7 million) relate to the regulatory deferral accounts identified above. In the absence of rate regulation, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. As a result of these tax impacts, earnings during the year would increase by $12.8 million (2006 – $16.4 million).

Allowance for Funds Used During Construction (AFUDC)

To date, an equity component of $67.3 million (2006 – $67.3 million) is included in property, plant and equipment.

With the pool method prescribed by the regulator of Alliance Canada, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation for specific assets. Similarly, gains or losses on the retirement of specific fixed assets in any given year cannot be identified or quantified.

5. SEGMENTED INFORMATION

(millions of dollars) **Year ended December 31, 2007**	Alliance Canada	Saskatchewan System	Green Power	Corporate	Consolidated
Revenue	**209.1**	**54.4**	**7.3**	**–**	**270.8**
Operating and maintenance	**(43.5)**	**(27.4)**	**(2.3)**	**–**	**(73.2)**
Management and administrative	**–**	**–**	**–**	**(4.8)**	**(4.8)**
Depreciation and amortization	**(62.0)**	**(16.6)**	**(3.2)**	**–**	**(81.8)**
	103.6	**10.4**	**1.8**	**(4.8)**	**111.0**
Other income and expense	**0.9**	**(0.3)**	**0.4**	**0.2**	**1.2**
Interest expense	**(47.5)**	**–**	**–**	**(14.3)**	**(61.8)**
ECT preferred unit distributions	**–**	**–**	**–**	**(36.5)**	**(36.5)**
Income taxes	**2.0**	**9.2**	**0.4**	**(4.4)**	**7.2**
Earnings	**59.0**	**19.3**	**2.6**	**(59.8)**	**21.1**
Goodwill	**308.1**	**–**	**–**	**–**	**308.1**
Total assets	**1,516.3**	**261.9**	**78.8**	**1.8**	**1,858.8**
Capital expenditures	**17.9**	**21.1**	**17.2**	**–**	**56.2**

(millions of dollars) Year ended December 31, 2006	Alliance Canada	Saskatchewan System	Green Power	Corporate	Consolidated
Revenue	201.4	51.7	1.3	–	254.4
Operating and maintenance	(36.0)	(25.4)	(0.4)	–	(61.8)
Management and administrative	–	–	–	(4.3)	(4.3)
Depreciation and amortization	(61.3)	(16.7)	(0.5)	–	(78.5)
	104.1	9.6	0.4	(4.3)	109.8
Other income and expense	1.0	(0.3)	0.2	0.1	1.0
Interest expense	(48.7)	–	–	(11.4)	(60.1)
ECT preferred unit distributions	–	–	–	(35.2)	(35.2)
Income taxes	2.6	17.7	–	(0.5)	19.8
Earnings	59.0	27.0	0.6	(51.3)	35.3
Goodwill	308.1	–	–	–	308.1
Total assets	1,539.0	255.3	67.2	5.8	1,867.3
Capital expenditures	10.5	12.2	10.1	–	32.8

6. ACQUISITION

On October 1, 2006, the Fund purchased Enbridge's interests in three wind power projects including a 50% interest in the SunBridge project at Gull Lake, Saskatchewan, and a 33.3% interest in each of the Magrath and Chin Chute projects in Southern Alberta, for $42.1 million. The acquisition was financed through the existing credit facility.

The acquisition was accounted for using the purchase method. Earnings from the acquired assets have been included as of October 1, 2006.

(millions of dollars)

Year ended December 31,	2006
Fair Value of Assets and Liabilities Acquired	
Property, plant and equipment	41.8
Intangible assets	4.0
Working capital	0.5
Asset retirement obligations	(0.3)
Future income taxes	(3.9)
	42.1
Purchase Price	
Cash (includes cash acquired of $0.6 million)	41.2
Transaction costs	0.9
	42.1

Enbridge is a related party to the Fund by virtue of its 41.9% equity interest in the Fund as well as its ownership of the Fund's ECT preferred units. The transaction has been recorded at fair value, which was approved by the Fund's Independent Trustees who were supported by independent financial, legal and technical advisors.

In conjunction with the purchase transaction, the Fund entered into a contract with Enbridge whereby Enbridge agreed to purchase all available emission reduction credits generated by the Fund's interest in the Chin Chute and Magrath projects over an initial 20-year term ending October 1, 2026 for a fixed price of $5 per tonne, based on a negotiated rate of converting megawatt hours generated to tonnes of emissions reduced, plus applicable taxes. Also in conjunction with the purchase transaction, to reduce the uncertainty associated with government support programs, Enbridge agreed to pay the Fund $10 per megawatt hour (MWh) of power produced by the Fund's interest in Chin Chute until such time that Wind Power Production Incentive (WPPI) or similar successor program funding was reinstated. These agreements are collectively referred to as the Production Incentive Agreements.

7. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars)

December 31,	**2007**	2006
Regulatory receivable	**65.6**	48.0
Deferred financing charges (Note 3)	**–**	10.1
Other deferred amounts	**9.4**	2.2
	75.0	60.3

In July 2007, Alliance Canada acquired a $12.4 million investment in asset-backed commercial paper issued by a structured investment trust (the Trust). The investment is held in trust with Alliance Canada's Security Trustee as part of Alliance Canada's current debt service requirement. As a result of the liquidity issues arising in the asset-backed commercial paper market, the Trust was unable to redeem this investment upon its maturity on August 31, 2007. Since there is no active market for asset-backed commercial paper, the investment has been reclassified to other deferred amounts. The investment continues to be classified as a held-for-trading instrument. Due to the uncertainty involved in estimating the amount and timing of cash flows associated with this investment, Alliance Canada has incorporated a discounted cash flow approach to estimate the investment's fair value using the best information currently available. As a result, the Fund recognized a fair value discount of $0.4 million. This estimate of fair value may differ from the actual fair value that will be realized. The Fund's 50% share of the investment is recognized in other deferred amounts above.

The Fund does not anticipate that the issues surrounding its investment in asset-backed commercial paper will have any significant impact on the Alliance Canada's operations or ability to meet upcoming debt obligations.

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) **December 31, 2007**	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Alliance Canada				
Pipeline in service	**4.0%**	**1,249.2**	**(244.8)**	**1,004.4**
Plant assets	**15.0%**	**3.2**	**(2.1)**	**1.1**
Capital spares	**–**	**5.6**	**–**	**5.6**
Other assets	**31.7%**	**10.8**	**(8.7)**	**2.1**
		1,268.8	**(255.6)**	**1,013.2**
Saskatchewan System				
Pipeline in service	**5.3%**	**298.6**	**(68.8)**	**229.8**
Line fill	**–**	**5.3**	**–**	**5.3**
Under construction	**–**	**13.0**	**–**	**13.0**
		316.9	**(68.8)**	**248.1**
Green Power				
Machinery and equipment	**4.4%**	**49.8**	**(2.9)**	**46.9**
Other assets	**5.3%**	**1.8**	**(0.2)**	**1.6**
Under construction	**–**	**19.2**	**–**	**19.2**
		70.8	**(3.1)**	**67.7**
		1,656.5	**(327.5)**	**1,329.0**

(millions of dollars) December 31, 2006	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Alliance Canada				
Pipeline in service	4.0%	1,233.5	(189.4)	1,044.1
Plant assets	15.5%	2.9	(1.8)	1.1
Capital spares	–	5.6	–	5.6
Other assets	31.0%	8.9	(7.4)	1.5
		1,250.9	(198.6)	1,052.3
Saskatchewan System				
Pipeline in service	5.7%	284.3	(53.0)	231.3
Line fill	–	5.3	–	5.3
Under construction	–	6.9	–	6.9
		296.5	(53.0)	243.5
Green Power				
Machinery and equipment	3.6%	46.9	(0.4)	46.5
Other assets	5.6%	1.8	–	1.8
Under construction	–	4.9	–	4.9
		53.6	(0.4)	53.2
		1,601.0	(252.0)	1,349.0

9. INTANGIBLE ASSETS

(millions of dollars) **December 31, 2007**	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Alliance Canada				
Long term transportation agreements	**4.4%**	**116.0**	**(23.2)**	**92.8**
Green Power				
Production incentive agreements	**8.4%**	**4.0**	**(0.4)**	**3.6**
		120.0	**(23.6)**	**96.4**

(millions of dollars) December 31, 2006	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Alliance Canada				
Long term transportation agreements	4.4%	116.0	(18.0)	98.0
Green Power				
Production incentive agreements	8.4%	4.0	(0.1)	3.9
		120.0	(18.1)	101.9

10. LONG TERM DEBT

(millions of dollars) December 31,	**2007**	2006
Medium Term Notes		
4.19% due December 21, 2009	**100.0**	100.0
5.25% due December 22, 2014	**90.0**	90.0
Credit Facility	**98.5**	69.0
Deferred Financing Charges (Note 3)	**(4.3)**	–
	284.2	259.0

MEDIUM TERM NOTES

The Medium Term Notes (MTNs) are unsecured and redeemable by the Fund prior to maturity, in whole or in part, at the option of the Fund at the Government of Canada yield plus 0.14% and 0.25% for the Series 1 and Series 2 MTNs, respectively. Interest on the MTNs is payable semi-annually in June and December.

CREDIT FACILITY

On September 30, 2007, the Fund amended the existing three-year unsecured credit facility to increase the facility from $105.0 million to $150.0 million under the same terms and conditions as the previously existing facility.

The Fund may receive advances on the credit facility up to an aggregate principal amount of the credit limit by requesting prime rate advances, U.S. base rate advances, U.S. LIBOR advances, letter of credit advances, bankers' acceptance advances, or by requesting bankers' acceptance equivalent loans. Interest is charged at a rate per annum, dependent on the type of advance requested plus applicable margin. The current applicable margins range from nil to 0.53%. The maturity date of the credit facility is February 10, 2010.

At December 31, 2007, the Fund's credit facility had $0.2 million (2006 – $0.9 million) of letters of credit outstanding and $51.3 million (2006 – $35.1 million) in undrawn credit available.

11. NON RECOURSE LONG TERM DEBT

(millions of dollars)

December 31,	**2007**	2006
Alliance Canada		
Bank credit facility	**43.0**	25.4
Senior notes		
7.230% due 2015	**117.4**	121.4
7.181% due 2023	**174.8**	180.8
5.546% due 2023	**107.4**	113.6
7.217% due 2025	**139.9**	144.5
6.765% due 2025	**168.2**	173.4
Deferred Financing Charges (Note 3)	**(4.2)**	–
	746.5	759.1
Fair Value Increment on Long-Term Debt Acquired	**43.3**	48.3
Total Non-Recourse Debt	**789.8**	807.4
Current Portion of Non-Recourse Debt	**(28.7)**	(26.1)
Non-Recourse Long-Term Debt	**761.1**	781.3

Non-recourse long-term debt maturities for the years ending December 31, 2008 through 2012 are $28.7 million, $30.9 million, $33.9 million, $36.3 million, and $81.9 million, respectively, and $539.0 million thereafter.

ALLIANCE CANADA BANK CREDIT FACILITY

The credit facility consists of a committed extendible revolving credit facility in the amount of $200.0 million with an expansion provision to facilitate timely increases of the facility to $300.0 million if required. The credit facility has an initial term of five years with provisions for extension of one additional year. In June 2007, Alliance Canada extended the maturity date of its existing credit facility from June 28, 2011 to June 28, 2012.

Interest is accrued and payable based on bankers' acceptance rates, plus applicable margins, for terms not exceeding six months. Amounts outstanding under the credit facility at December 31, 2007 bear interest at an average rate of 4.65% (December 31, 2006 – 4.78%).

At December 31, 2007, Alliance Canada's credit facility had $80.0 million (2006 – $100.0 million) of letters of credit outstanding and $34.0 million (2006 – $49.2 million) in undrawn credit available, of which the Fund's proportionate share is 50%.

ALLIANCE CANADA SENIOR NOTES

The Fund recorded the senior notes at their fair value on the date of the acquisition of its interest in Alliance Canada. The difference between the fair value and the principal amount of the debt is amortized using the effective interest method over the remaining life of the debt. The senior notes are non-recourse to the Fund as security provided by Alliance Canada is limited to the rights and assets of Alliance Canada and does not extend to the rights and assets of the Fund, except to the extent of the Fund's investment in Alliance Canada.

The senior notes may be redeemed by Alliance Canada at any time at a price equal to the greater of (i) the applicable Government of Canada yield price plus a premium and (ii) par, together with accrued interest. Alliance Canada may be required to redeem the senior notes, in whole or in part, from proceeds received under insurance claims or other claims for damages if the proceeds are not applied to repair or rebuild the Alliance pipeline system.

Interest on the senior notes is payable semi-annually in June and December. Principal repayments are closely tied to the recovery rates for depreciation contained in the TSAs.

Certain assets of Alliance Canada are pledged as collateral to Alliance Canada's lenders and to the lenders to Alliance Pipeline L.P., which operates the United States portion of the Alliance pipeline system. Alliance Canada's long-term

debt is collateralized by a first priority perfected security interest in Alliance Canada's TSAs with its shippers, Alliance Canada's NEB permit, certain other material contracts, the trust accounts into which Alliance Canada's transportation revenue is deposited and a floating charge debenture over Alliance Canada's real property and tangible personal property. Alliance Canada is required to meet certain financial conditions and adhere to certain covenants on an ongoing basis.

12. INTEREST EXPENSE

(millions of dollars)

Year ended December 31,	2007	2006
Interest expense on:		
Long-term debt	**13.1**	10.0
Non-recourse long-term debt	**52.0**	53.3
Amortization of deferred financing fees and bank charges	**1.8**	2.0
Amortization of the fair value increment on debt	**(5.1)**	(5.2)
	61.8	60.1
Interest paid	**65.3**	63.3

13. ECT PREFERRED UNITS

The ECT preferred units are entitled to non-cumulative monthly distributions in an amount equal to the monthly distribution per ordinary unit. The ECT preferred units have no voting rights and mature on June 30, 2033, at which time ECT is obligated to redeem all of the outstanding ECT preferred units for a price of $10 per unit. At December 31, 2007 and 2006, 38,023,750 ECT preferred units were outstanding.

The ECT preferred units include both a debt and equity component as the holder has the option to request redemption based on a redemption price that is referenced to the market value of an ordinary unit. Upon request by the holder and satisfaction of the necessary conditions, including financing on terms acceptable to the Independent ECT Trustees, the ECT preferred units will be repurchased for cancellation by ECT with a repurchase price per ECT preferred unit based on the net issue price realized from the sale (or that could be realized from the sale) of an ordinary unit to the public. This redemption is paid in cash and the Fund must use its best efforts to finance the redemption request through the issue of additional equity or debt. As a result, it is necessary to record the fair value of the equity component at the date of issue. The equity component was assigned a nil value. Any gain or loss on the redemption of the debt component, based on the $10 per unit par value would be recorded as an equity transaction.

14. ASSET RETIREMENT OBLIGATIONS

(millions of dollars)

Year ended December 31,	2007	2006
Obligations at beginning of year	**7.9**	7.1
Liabilities acquired with Wind Power acquisition	–	0.3
Accretion expense	**0.5**	0.5
Liabilities settled	**(0.5)**	–
Obligations at end of year	**7.9**	7.9

A legal obligation exists for the retirement of assets within the Saskatchewan System and Green Power operating segments. The undiscounted amount of expected cash flows required to settle the asset retirement obligations is estimated at $43.5 million with the majority estimated to be settled beginning in the year 2033. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 6.58%.

15. TRUST UNITS

UNITS OUTSTANDING

(millions of Canadian dollars, except number of units)

December 31,	**2007**		2006	
	Number of Units	Amount	Number of Units	Amount
Ordinary Units	**20,125,000**	**188.4**	20,125,000	188.4
Subordinated Units	**14,500,000**	**145.0**	14,500,000	145.0
	34,625,000	**333.4**	34,625,000	333.4

Pursuant to the trust indenture, an unlimited number of each of the ordinary units and the subordinated units may be issued. Each unit represents an equal undivided beneficial interest in any distributions from the Fund and in the net assets in the event of termination or wind-up of the Fund. All units have equal rights and privileges except with respect to distributions of distributable cash for which ordinary units have priority. This priority will terminate on July 1, 2008 provided that during the immediately preceding 12 consecutive months the Fund has declared and paid aggregate distributions of at least $0.825 per ordinary unit. Otherwise, the priority continues until the Fund has declared and paid aggregate distributions of at least $0.825 per ordinary unit for 12 consecutive months.

Ordinary and subordinated units are redeemable at any time at the option of the holder. The redemption price is equal to the lesser of 90% of the weighted average market price of the units during a 10 day period occurring immediately prior to the redemption date and the closing market price on the redemption date. The total amount payable by the Fund in respect of redemptions in any calendar month shall not exceed $0.1 million. To the extent that a unitholder is not entitled to receive cash upon the redemption of the ordinary or subordinated units, the redemption price shall be satisfied by way of the Fund distributing a pro-rata number of ECT notes or other assets held by the Fund.

The Fund makes monthly distributions to unitholders of record on the last business day of each month. The amount of cash distributed monthly consists of all amounts received by the Fund including the income, interest, dividends, return of capital or other amounts, if any, from investments held by the Fund, less amounts that may be paid by the Fund in connection with any cash redemptions or repurchases of ordinary or subordinated units and amounts which the administrator or the Trustees of ECT may reasonably consider necessary for payment of costs and expenses required for the operation of the Fund and for reasonable reserves.

The Fund's policy is to distribute approximately 95% of cash available for distribution on average over a five-year period. However, due to short-term cash flow variability, this ratio will fluctuate on a year to year basis. In the event the Fund pursues activities which are consistent with the purposes of the Fund as outlined in the Trust Indenture, the Fund has the discretion to set aside reasonable reserves for such amounts, thereby reducing the percentage of cash available distributed. For the year ended December 31, 2007, the Fund declared $33.1 million (2006 – $32.1 million) in cash distributions to ordinary and subordinated unitholders. Cash distributions of $36.5 million (2006 – $35.2 million) were also declared on the ECT preferred units during the year ended December 31, 2007.

16. FINANCIAL INSTRUMENTS

DERIVATIVE FINANCIAL INSTRUMENTS USED FOR RISK MANAGEMENT

The Fund is exposed to movements in interest rates and the price of power. From time to time, in order to manage these exposures, the Fund uses derivative financial instruments to create offsetting financial positions. These exposures include the following:

Interest Rates

There are no interest rate derivative financial instruments outstanding at December 31, 2007 and 2006.

Power Price

The Fund is exposed to movements in the price of power through its interest in wind power assets. To manage this exposure, the Fund uses two fixed price power agreements that convert the floating price received from sale to the Alberta pool to a fixed rate.

CREDIT RISK

Alliance Canada is exposed to credit risk since its business is concentrated in the natural gas transportation industry and its revenue is dependent upon the ability of its shippers to pay their monthly demand charges. A majority of the shippers operate in the oil and gas exploration and development or energy marketing/transportation industries and may be exposed to long-term downturns in energy commodity prices, including the price for natural gas, or other events impacting the creditworthiness of these industries. Alliance Canada limits, to some degree, its exposure to this credit risk by requiring its shippers to provide letters of credit or other suitable security unless they maintain specified credit ratings or financial positions.

The Saskatchewan System's trade receivables consist primarily of amounts due from companies operating in the oil and gas industry. The credit risk associated with these receivables is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements.

Green Power is exposed to credit risk since each project's primary source of fixed price revenue is a single counterparty. This risk is mitigated by requirements for counterparties to maintain specified credit ratings.

FAIR VALUES

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The fair values of other financial instruments reflect the Fund's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates.

The aggregate fair value of the senior notes in Alliance Canada is \$796.8 million (2006 – \$850.1 million) based on quoted market prices. The fair values of the Series 1 MTNs and the Series 2 MTNs of the Fund, based on quoted market prices for similar issues, are \$98.1 million (2006 – \$99.1 million) and \$88.0 million (2006 – \$92.2 million), respectively. The approximate fair value of the ECT preferred units, valued at the December 31, 2007 closing price of \$10.25 per ordinary unit (2006 – \$13.20), is \$389.7 million (2006 – \$501.9 million).

HEDGING ACTIVITIES

The Fund uses the following cash flow hedges to manage changes in power prices.

(millions of Canadian dollars, unless otherwise noted)	**2007** Notional Principal or Quantity	**2007** Fair Value Receivable/ (Payable)	**2007** Maturity	2006 Notional Principal or Quantity	2006 Fair Value Receivable/ (Payable)	2006 Maturity
ChinChute Power Swap (MW/H)	**2.0**	**(3.8)**	**2017**	3.0	(2.5)	2017
Magrath Power Swap (MW/H)	**2.8**	**(4.6)**	**2024**	2.8	(3.6)	2024
	4.8	**(8.4)**		5.8	(6.1)	

At December 31, 2007, the Fund has recorded a liability of \$8.4 million for the unrealized fair value of effective cash flow hedges as well as a future income tax asset of \$2.4 million for these cash flow hedges. Realized net losses of \$0.3 million (after tax) from the Fund's power purchase swap agreements were recorded in revenue in the year. The Fund estimates that \$1.0 million of AOCI will be reclassified to earnings in the next 12 months.

NON-HEDGING DERIVATIVES

The Fund does not use derivative instruments for speculative purposes. However, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as a hedging item, changes in the fair value are recorded in current period earnings. The Fund recognized net unrealized mark to market derivative gain of \$0.5 million (after tax) for the year ended December 31, 2007 (2006 – \$nil) related to non-qualifying instruments.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

(millions of dollars)

Year ended December 31,	**2007**	2006
Earnings before income taxes	**13.9**	15.5
Combined statutory income tax rate	**32.1%**	32.5%
Income taxes at statutory rate	**4.5**	5.0
Increase/(decrease) resulting from:		
Interest deductions of subsidiaries arising from intercorporate debt	**(20.8)**	(20.1)
Legislated tax changes on future income tax balances	**(6.6)**	(16.3)
Distributions on ECT preferred units	**11.7**	11.4
Deductions allocated to unitholders	**6.0**	4.9
Future income taxes related to regulated operations	**(2.0)**	(3.8)
Other	**–**	(0.9)
Income taxes/(recovery)	**(7.2)**	(19.8)
Effective income tax rate	**(51.8%)**	(127.7%)

COMPONENTS OF FUTURE INCOME TAXES

(millions of dollars)

December 31,	**2007**	2006
Future income tax liabilities/(assets)		
Differences in accounting and tax bases of:		
Property, plant and equipment and intangible assets	**78.2**	91.2
Fair value increment on long-term debt acquired	**(11.6)**	(14.2)
Asset Retirement Obligation	**(2.1)**	(2.3)
OCI	**(2.4)**	–
Other	**(0.7)**	(1.9)
	61.4	72.8

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. This change resulted in the recognition of future income tax liabilities and expense of $1.9 million in the second quarter of 2007. This future income tax liability was reduced by $0.6 million as a result of the 3.5% reduction in the future income tax rates substantially enacted in December 2007. The enactment of Bill C-52 also resulted in a future income tax asset and an offset to AOCI to tax effect the unrealized fair value of power purchase swap agreements, which at December 31, 2007 was $2.4 million. Future income tax expense was not recorded for the temporary differences attributed to Alliance Canada because future income taxes are expected to be included in the approved rates charged to customers in the future and fully recovered.

Current income taxes were $1.9 million (2006 – $0.4 million.)

At December 31, 2007, the Fund has recognized the benefit of unused loss carryforwards of $2.4 million (2006 – $6.3 million). Unused tax loss carryforwards expire as follows: 2015 – $0.1 million and 2026 – $2.3 million.

18. JOINT VENTURES

The Fund's proportionate share of the net assets, earnings, cash flows and financial position of its interests in joint ventures is summarized below. This summary does not include the impact of the purchase price excess that resulted upon the acquisition of the joint ventures.

NET ASSETS

(millions of dollars) December 31,	Ownership Interest	**2007**	2006
Alliance Canada	50%	**355.2**	358.5
Green Power			
NRGreen	50%	**27.6**	12.3
SunBridge	50%	**8.9**	9.6
Magrath	33%	**13.4**	14.6
ChinChute	33%	**19.3**	20.0
		424.4	415.0

EARNINGS

(millions of dollars) Year ended December 31,	**2007**	2006
Revenues	**216.0**	203.3
Operating and maintenance	**(45.0)**	(35.4)
Depreciation and amortization	**(59.2)**	(56.5)
Interest expense	**(52.6)**	(54.0)
Other income and expense	**1.2**	1.1
Proportionate share of net earnings	**60.4**	58.5

CASH FLOWS

(millions of dollars) Year ended December 31,	**2007**	2006
Cash provided by operating activities	**97.1**	100.1
Cash used in investing activities	**(44.3)**	(17.5)
Cash used in financing activities	**(54.6)**	(93.8)
Proportionate share of decrease in cash and cash equivalents	**(1.8)**	(11.2)

FINANCIAL POSITION

(millions of dollars) December 31,	**2007**	2006
Current assets	**34.5**	36.0
Property, plant and equipment	**1,079.0**	1,103.4
Deferred amounts and other assets	**74.8**	54.4
Current liabilities	**(42.6)**	(40.9)
Non-recourse long-term debt	**(717.9)**	(733.1)
Long-Term liabilities	**(3.2)**	(4.8)
Asset retirement obligation	**(0.2)**	–
Proportionate share of net assets	**424.4**	415.0

Included in the Fund's proportionate share of cash from Alliance Canada is $2.4 million (2006 – $4.0 million) of cash that is held in trust. Under the terms of Alliance Canada's finance agreements, all funds received from shippers in settlement of transportation tolls, as well as interest earned on trust account balances, are segregated in trust

accounts and first applied to meet debt service and operating requirements before distributions, if any, are made to the partners. At the completion of each fiscal quarter, Alliance Canada determines the amount of cash and cash equivalents necessary to satisfy this requirement and applies to have funds, if any, in excess of this amount transferred to a non-trust account. Only funds in non-trust accounts may be distributed to the partners of Alliance Canada.

19. RELATED PARTY TRANSACTIONS

Alliance Canada has contracts with shippers who are also affiliates of the Fund through common ownership interests of Enbridge. The Fund's share of Alliance Canada's revenue from affiliates for the year ended December 31, 2007 is $12.3 million (2006 – $21.1 million) of which $1.0 million is included in accounts receivable. The terms of these contracts are the same as those agreed to with independent third parties.

Administrative and operation services agreements allow for Alliance Canada to provide services to Alliance US (an entity related to Alliance Canada by virtue of common ownership interests) in exchange for reimbursement of incurred costs or at rates consistent with those obtainable from independent third parties. Certain amounts reimbursed under the services agreements with Alliance Pipeline L.P. also include a recovery of costs relating to the use of common administrative assets. The Fund's share of amounts charged to Alliance Pipeline L.P. during the year ended December 31, 2007 was $10.1 million (2006 – $8.8 million) of which $0.7 million (2006 – $0.2 million) was included in accounts receivable as at December 31, 2007.

The Saskatchewan System does not have any employees and uses the services of Enbridge, which has a 41.9% equity ownership interest in the Fund, for managing and operating the business. These services, which are charged at cost in accordance with service agreements, amounted to $12.7 million for 2007 (2006 – $12.4 million) of which $0.8 million (2006 – $1.8 million) was included in payables at December 31, 2007.

The SunBridge project does not have any employees and uses the services of Enbridge for managing and operating the business. These services, which are charged at cost, amounted to $0.3 million for 2007 (2006 – $nil) with $0.1 million included in accounts payable at December 31, 2007 (2006 – $nil).

Under the management and administrative agreements with EMSI, a wholly owned subsidiary of Enbridge, an incentive fee is payable annually to EMSI equal to 25% of cash distributions above a base distribution level of $0.825 per unit per year. During the year ended December 31, 2007, incentive fees amounted to $3.5 million (2006 – $2.4 million), which were included in accounts payable at December 31, 2007 (2006 – $2.4 million). In addition, a base fee for providing administrative and management services is payable annually and is $0.1 million for the year ended December 31, 2007 (2006 – $0.1 million).

20. COMMITMENTS

At December 31, 2007, the Fund had operating lease obligations as detailed below:

(millions of dollars)	Total	Less than 1 year	2 years	3 years	4 years	5 years	After 6 years
Operating Leases	36.0	3.1	2.9	3.2	3.2	2.8	20.8

At December 31, 2007, the Fund has commitments of $8.1 million relating to both Alliance Canada's purchase of and maintenance of compressor equipment and NRGreen's capital commitments for the completion of the Loreburn, Estlin, and Alameda waste heat reduction facilities in 2008.

21. SUBSEQUENT EVENTS

DISTRIBUTION BY THE FUND

On January 15, 2008, the Fund made a monthly cash distribution in the amount of $0.08 per ordinary unit. A cash distribution of $0.08 per unit was also paid on the same date on the subordinated units and the ECT preferred units.

On January 18, 2008, the Fund declared a monthly cash distribution in the amount of $0.08 per ordinary unit to unitholders of record on January 31, 2008, which is payable on February 15, 2008. Cash distributions of $0.08 per unit were also declared on the same date on the subordinated units and the ECT preferred units.

CALPINE ENERGY SERVICES CANADA PARTNERSHIP *(CESCA)* CLAIM SETTLEMENT

In 2006, CESCA, a shipper on the Alliance system accounting for 1.5% of firm capacity, repudiated its firm transportation service agreement with Alliance Canada. Alliance Canada immediately arranged for the placement of this capacity and drew on CESCA's letter of credit for funds equal to twelve months of demand charges in respect of CESCA's former transportation capacity. The funds were deposited into an account held in trust with Alliance's Security Trustee to be applied against any shortfall on tolls arising from the new placement. Transportation revenue for 2007 was unaffected by this repudiation due to the re-marketing of the transportation capacity and utilization of the funds received as security.

In 2006, Alliance Canada and Alliance US filed proofs of claim in the Calpine Corporation Chapter 11 Bankruptcy proceedings. These claims in respect of guarantees provided by Calpine Corporation as security for the performance of CESCA's obligations under its transportation contracts. In 2007, an agreement with CESCA and related Calpine entities was reached, which provided Alliance Canada and Alliance US with one general unsecured claim against CESCA. On January 16, 2008, full payment for settlement of the two claims totaling $20.7 million was received.

UNITHOLDER AND INVESTOR INFORMATION

Ordinary Units
The ordinary units of Enbridge Income Fund are listed in Canada on the Toronto Stock Exchange and trade under the symbol "ENF.UN".

Fund Trustee/Registrar and Transfer Agent
CIBC Mellon Trust Company
600, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1
Telephone: (403) 232-2400
Toll free: (800) 387-0825
Internet: www.cibcmellon.com

Fund Administrator
Enbridge Management Services Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920

Auditors
PricewaterhouseCoopers LLP

Tax Information
The Fund is a "mutual fund trust" as defined in the Income Tax Act (Canada) (the "Act"). Units in the Fund are qualified investments for registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans under the Act.

Cash distributions to unitholders include an income or taxable component and a return of capital component. The specific breakdown of distributions in a particular year will be provided to the unitholders after the end of the year.

Based on current operations, the Fund estimates that approximately 80% of cash to be distributed during 2008 will be included in the income of unitholders for tax purposes.

The taxable component will be mainly ordinary income for tax purposes although there will be a dividend component that will qualify for the dividend tax credit when received by an individual resident in Canada. The portion of a distribution that is considered a return of capital is not immediately taxable but rather reduces the unitholder's tax basis in the unit.

Holders and potential holders of Fund units should consult their own tax advisors with respect to their particular circumstances.

Cash Distributions
Monthly distributions will be made to unitholders of record as of the close of business on the last business day of each month, and are expected to be paid to unitholders on or about the 15th day of the following month. The following expected distribution dates for 2008 are subject to the distributions being declared by the Board of Trustees.

Record date	Payment date
December 31, 2007	January 15, 2008
January 31	February 15
February 29	March 14
March 31	April 15
April 30	May 15
May 30	June 13
June 30	July 15
July 31	August 15
August 29	September 15
September 30	October 15
October 31	November 14
November 28	December 15

Dividend Reinvestment and Unit Purchase Plan
In June 2004, the Fund began a Distribution Reinvestment and Unit Purchase Plan (the "Plan"). Participants may elect, without brokerage fees, to automatically reinvest monthly distributions in additional units of the Fund, and may make optional cash payments of up to $1,000 per month (subject to a minimum of $100 per month) to purchase additional units of the Fund. Details of the Plan are available on the Fund's website. Investors should contact their respective investment dealer to enroll.

In order to be eligible to participate in the Plan, unitholders must be resident in Canada and hold a minimum of 100 ordinary trust units. Unitholders resident outside of Canada will be entitled to participate in the Plan subject to applicable local law. U.S. residents and citizens are not eligible to participate.

Executive Office
Enbridge Income Fund
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900

Investor Inquiries

If you have inquiries regarding the following:

- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations

Please contact Enbridge Investor Relations or visit Enbridge Income Fund's web site at **www.enbridgeincomefund.com.**

Investor Relations

3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804
Facsimile: (403) 231-3920

Annual Meeting

The annual meeting of unitholders will be held in the Lecture Theatre of the Metropolitan Conference Centre, Calgary, Alberta, at 1:30 p.m. MDT on Monday, May 5, 2008.

Quarterly Unit Trading Information
The Toronto Stock Exchange

2007 (dollars)	First	Second	Third	Fourth	Annual
High	**13.07**	**12.75**	**12.14**	**11.26**	**13.07**
Low	**10.42**	**11.14**	**9.63**	**9.20**	**9.20**
Close	**11.37**	**11.35**	**9.81**	**10.25**	**10.25**
volume (millions)	**2.32**	**1.69**	**1.81**	**3.81**	**9.63**
2006 (dollars)	First	Second	Third	Fourth	Annual
High	14.75	13.70	13.99	14.54	14.75
Low	12.95	11.80	12.69	9.61	9.61
Close	13.15	13.00	13.68	13.20	13.20
volume (millions)	2.76	1.70	1.71	3.37	9.54

Designed and Produced by Karo Group Calgary. Printed in Canada by Blanchette Press.

Recycled
Supporting responsible use of forest resources
www.fsc.org Cert no. SW-COC-2068
© 1996 Forest Stewardship Council
FSC

Printed on FSC Certified Mohawk Options 100% PCW, which is manufactured entirely with wind energy and contains 100% post-consumer recycled fibre.

ENBRIDGE INCOME FUND

Enbridge Income Fund's ordinary units trade on the Toronto Stock Exchange under the symbol ENF.UN.

Enbridge Income Fund
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Fax: (403) 231-3920
www.enbridgeincomefund.com